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February 28, 2019

Ms. Mary Loos
Secretary of the Commission
Arkansas Public Service Commission
Office of the Secretary
1000 Center Street
Little Rock, AR 72201

Re: APSC Docket No. 19-008-U

Dear Ms. Loos:

The Application of Southwestern Electric Power Company for a General Change in Rates and Tariffs, together with the required Minimum Filing Requirement schedules, accompanies this electronic filing. Also being filed are the direct testimony and exhibits of the following witnesses in support of the Application:

Malcolm Smoak
Thomas Brice
John Aaron
Jennifer Jackson
Mark Becker
David Davis
Paul Franklin
Franklin Pifer
Jason Yoder
Kurt Strunk
Robert Hevert

Workpapers supporting the testimony and exhibits are being contemporaneously provided to the current parties of record.

Thank you for your attention to this matter. Please call if you have any questions or need additional information.

Sincerely,

/s/ Stephen K. Cuffman

Stephen K. Cuffman

cc: All Parties of Record
Regina Butler
Elizabeth Stephens

Arkansas Public Service Commission
General Rate Case Docket Summary Cover Sheet
Must be filed with each new docket filed at the Commission

STYLE OF DOCKET: (Style may be changed by Secretary of Commission)	**Docket Number:**
IN THE MATTER OF THE APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR A GENERAL CHANGE IN RATES AND TARIFFS	19-008-U

DOCKET DESIGNATOR: ☒ U

LAST RATE CASE DOCKET: 09-008-U

Date Notice of Intent filed by company: 12/10/2018

PETITIONER/INITIATING PARTY	ATTORNEYS' NAME, ADDRESS, PHONE, FAX AND E-MAIL	
SOUTHWESTERN ELECTRIC POWER COMPANY	Stephen K. Cuffman Matthew B. Finch Gill Ragon Owen, P.A. 425 W. Capitol Avenue Suite 3800 Little Rock, Ar 72201 (501) 376-3800 cuffman@gill-law.com	David R. Matthews Matthews, Campbell, Rhoads, McClure and Thompson, P.A. 119 South Second St. Rogers, Ar 72756 (479) 636-0875 drm@mcrmt.com

Pursuant to Rule 3.04 of the Commission's Rules of Practice and Procedure, please provide name, address, phone, fax, e-mail of at least one person, but not more than two, to appear on the Service List for this docket

Stephen K. Cuffman Gill Ragon Owen, P.A. 425 W. Capitol Avenue Suite 3800 Little Rock, Ar 72201 (501) 376-3800 cuffman@gill-law.com	Jay E. Toungate Regulatory Case Manager Southwestern Electric Power Company 1201 Elm Street, Suite 800 Dallas, Tx 75270 (214)777-1055 jetoungate@aep.com

1. Company's current authorized retail revenue requirement: $170,444,837 See Note 1 on following page
2. Retail revenue requirement requested: $228,041,023 See Note 2 on following page
3. Percentage increase by rate class (i.e., residential, commercial, industrial, etc). For percentage increase by rate class, including fuel see Note 3 on following page.
4. Estimated monthly impact on average residential customer in both dollars and percentage increase $22.60 or 24% per month at 1,000 kWh
5. Current authorized return on equity and overall rate of return: 10.25% ROE/6.01% Overall Rate of Return
6. Requested return on equity and overall rate of return: 10.5% ROE/5.21% Overall Rate of Return
7. Identify the major retail revenue requirement increase drivers, e.g., acquisition of new plant, higher requested, Return on equity, depreciation rate change, etc. Please continue on second page if more space is needed.

See Note 4 on following page.

Form completed by: Stephen K. Cuffman Date: 02/28/2019

Representing: Southwestern Electric Power Company

Notes:

1. $170,444,837 includes test year present base revenues of $129,184,908 authorized by Docket No. 09-008-U, Order No. 12 plus present rider revenues of $41,259,929 authorized by Docket No. 09-008-U, Order No. 29 (GR Rider), Docket No. 15-021-U, Order No. 14 (ECS Rider), and Docket No. 07-082-TF, Order No. 107 (EECR Rider). This amount does not include fuel (ECR Rider) revenues.

2. $228,041,023 includes test year proposed base revenues of $203,711,789 plus the requested DR Rider revenues of $12,000,339 plus remaining EECR Rider revenues of $12,328,895.

3. Class	Total Bill Percentage Change
Residential	23.7%
General Service	16.1%
Lighting & Power Secondary	21.3%
Lighting & Power Primary	16.9%
Lighting & Power TOU	29.2%
Large Lighting & Power Transmission	18.0%
Pulp & Paper Mill	11.6%
Municipal	9.3%
Private, Outdoor, & Area Lighting	-18.5%
Municipal Street & Public Street & Hwy Lighting	-18.5%
Total Retail	19.6%

4. Since its last rate adjustment in 2009, SWEPCO has made significant investment in its generation, transmission, distribution and customer service facilities, and has experienced substantial increases in operations and maintenance costs. SWEPCO also seeks rate base treatment for amounts being recovered in the GR Rider and Rider ECS. SWEPCO is also notifying the Commission that it elects to implement a Formula Rate Review Rider pursuant to Act 725 of 2015. Additionally, SWEPCO is requesting approval of a Distribution Reliability Rider or amount specifically earmarked in this case for vegetation management to improve reliability of its Arkansas distribution system

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR APPROVAL OF A GENERAL CHANGE IN RATES AND TARIFFS	**))))**	**DOCKET NO. 19-008-U**

APPLICATION

Southwestern Electric Power Company (SWEPCO or Company) files this application for approval of a general change in rates and tariffs, and in support thereof states:

1. SWEPCO is a corporation organized and existing under the laws of the State of Delaware, and is duly authorized to do business in the States of Arkansas, Louisiana, Texas, and Oklahoma. SWEPCO's principal office is at 428 Travis Street, Shreveport, Louisiana.

2. In the States of Arkansas, Louisiana, and Texas, SWEPCO engages in a general electric utility business of selling, at retail and wholesale, electric power and energy to customers in its service areas. SWEPCO provides service to approximately 535,000 retail customers, of which approximately 119,000 are located in Arkansas. Electricity is provided by 12 generating facilities, which the Company owns in whole or in part, and pursuant to purchased power agreements, and is delivered to customers in the Company's service areas via an integrated transmission and distribution system.

3. SWEPCO is a public utility as defined by Ark. Code Ann. § 23-1-101 *et seq.*, and is therefore subject to the jurisdiction of the Commission. Approval of new rates and charges is sought hereunder pursuant to the provisions of Ark. Code. Ann. § 23-4-402 *et seq.*, and Sections 4 and 8 of the Commission's *Rules of Practice and Procedure*.

4. SWEPCO's books and records are kept in accordance with the Uniform System of Accounts, pursuant to the rules and regulations of this Commission and of the Federal Energy Regulatory Commission. All utility plant accounts are stated at original cost.

5. This Application is based upon a forward-looking test year consisting of historical data for the seven month period ending July 31, 2018, and projected data for the five month period ending December 31, 2018, adjusted for reasonably known and measurable changes through December 31, 2019. The revised rates requested by SWEPCO are designed to recover equalized rates of return from all customer classes, except as adjusted for other considerations in accordance with Commission policy.

6. SWEPCO is submitting with this Application the Minimum Filing Requirement Schedules required by Section 8 of the Commission's *Rules of Practice and Procedure*. Changes to SWEPCO's current rates, charges, and terms and conditions of service are indicated in the proposed tariff attached hereto. These changes will go into effect in thirty (30) days unless the Commission suspends the tariff pursuant to Ark. Code Ann. § 23-4-407, as is customary in general rate case applications. In such event, SWEPCO anticipates that new rates and charges will become effective no later than December 28, 2019.

7. SWEPCO's last increase in base rates was in 2009 in Docket No. 09-008-U. Since its last rate adjustment in 2009, SWEPCO has invested nearly $700 million in environmental upgrades at the Company's Flint Creek, Welsh, Dolet Hills and Pirkey generating plants to enable continued operation of those facilities in compliance with the federal Clean Air Act and regulations promulgated by the Environmental Protection Agency. Those costs are currently recovered through Act 310 surcharges approved in Docket No. 15-021-U. Those investments will now be placed into rate base. Since its last rate adjustment, SWEPCO also completed

construction of the J. Lamar Stall generating plant, which is currently recovered through a rider approved in Docket No. 09-008-U. The Company's investment in the Stall Plant is now being placed into rate base. While base rates will increase with the rate base treatment of these facilities, customer impacts should not significantly change due to the elimination of the Act 310 surcharges and the Stall rider. In addition, the Company made significant investment in its generation, transmission, distribution and customer service facilities, and has experienced substantial increases in operations and maintenance costs. As a result, SWEPCO needs increased revenue through revised rates in order to have a reasonable opportunity to recover prudently incurred costs and a fair opportunity to earn a reasonable return on investment. Accordingly, SWEPCO is seeking an increase in revenue to recover a retail revenue deficiency of $74.5 million in base rates. This amount includes additional capital investments and increased O&M expenses since the 2009 rate case, as well as SWEPCO's request for rate base treatment for the Stall Plant and the environmental retrofits currently recovered through riders. Eliminating those existing riders results in a net annual increase of $57.6 million representing $45.6 million increase in the Company's non-fuel base rates, plus $12 million for increased vegetation management.

8. If the increase in rates requested herein is granted, SWEPCO will continue to be a low cost provider, with rates still well below the national average. The effect of the base rate increase requested by this Application will be approximately 19.6% in Arkansas jurisdictional total revenues, including fuel. This request will result in an increase of approximately $22.60 (24%) per month for a residential customer consuming 1,000 kWh per month.

9. In 2015, the 90th General Assembly enacted Act 725 of 2015, known as the Formula Rate Review Act. Act 725 authorized utilities to elect, subject to filing a notice with the APSC as part of a general rate case, to have its rates regulated under a formula rate review mechanism. SWEPCO hereby provides notice of its election to have its rates regulated under the formula rate review mechanism authorized by Act 725. The Company is proposing with this filing a Formula Rate Review Rider, which complies with the provisions of Act 725.

10. SWEPCO also is requesting approval of a Distribution Reliability Rider ("DR Rider") that will enable the Company to establish a four year cycle for vegetation management. Managing vegetation on a four year cycle will greatly reduce outages, thereby improving reliability and customer satisfaction.

11. All correspondence in this docket should be addressed to:

Jay E. Toungate
Regulatory Case Manager
Southwestern Electric Power Company
1201 Elm Street, Suite 800
Dallas, TX 75270
(214) 777-1055
jetoungate@aep.com

Stephen K. Cuffman
Gill Ragon Owen, P.A.
425 W. Capitol Avenue
Suite 3800
Little Rock, AR 72201
(501) 376-3800
cuffman@gill-law.com

12. In support of this Application, SWEPCO submits herewith the prepared testimonies and exhibits of Malcolm Smoak, Thomas Brice, Robert Hevert, Jason Yoder, John Aaron, Paul Franklin, Frank Pifer, Kurt Strunk, Mark Becker, David Davis and Jennifer Jackson. Pursuant to Rule 8.08 of the Commission's *Rules of Practice and Procedure*, the Company is

contemporaneously providing the work papers supporting the testimony of its witnesses to APSC Staff.

13. Notice of the filing of this Application, as required by Rule 8.07 of the Commission's *Rules of Practice and Procedure*, will be promptly published and proof thereof shall be filed with the Commission promptly after publication is completed.

WHEREFORE, Southwestern Electric Power Company respectfully requests that, upon consideration of the foregoing Application and supporting testimony and rate case schedules, the Commission approve the general change in rates, charges, and terms and conditions of service described herein, and for all other appropriate relief.

Respectfully submitted,

/s/ Stephen K. Cuffman

Stephen K. Cuffman (75026)
Matthew B. Finch (200125)
Gill Ragon Owen, P.A.
425 West Capitol Avenue
Suite 3800
Little Rock, Arkansas 72201
(501) 376-3800

and

David R. Matthews (76072)
MATTHEWS, CAMPBELL, RHOADS
McCLURE, THOMPSON & FRYAUF, P. A.
119 South Second Street
Rogers, Arkansas 72756
(479) 636-0875

Attorneys for Southwestern Electric Power Company

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing Application has been electronically served upon all parties of record via the Commission's EFS system on this 28th day of February, 2019.

/s/ Stephen K. Cuffman
Stephen K. Cuffman

SOUTHWESTERN ELECTRIC POWER COMPANY
CALCULATION OF REQUESTED INCREASE IN REVENUE REQUIREMENT
TEST YEAR ENDING DECEMBER 31, 2018
DOCKET NO. 19-008-U

I. Test Year Information

1 Test year ending December 31, 2018 — 12/31/2018

2 Test year is 7 months of historical (Jan-Jul) and 5 months of forecasted (Aug- Dec).

II. Calculation of Revenue Requirement

Line No.	Description	Arkansas Jurisdiction
1	Adjusted Rate Base (a)	1,181,137,178
2	Adjusted Operating Revenues (b)	156,932,888
3	Adjusted Operating Expenses (b)	150,238,938
4	Adjusted Operating Income (b)	6,693,949
5	Current Rate of Return (line 4/line 1)	0.57%
6	Required Rate of Return (c)	5.21%
7	Required Operating Income (line 1 x line 6)	61,566,775
8	Operating Income Deficiency (line 7 - line 4)	54,872,826
9	Revenue Conversion Factor (d)	1.358174
10	Revenue Deficiency (line 8 x line 9)	74,526,851
11	Total Non-Fuel Revenue Requirement (line 2 + line 10)	231,459,739
12	Adjusted Revenues Other than Rate Schedule Revenue (b)	27,747,979
13	Rate Schedule Revenue Requirement (line 11- line 12)	203,711,760
14	Percentage Increase in Total Revenue Requirement (line 10/line 2)	47.49%

Supporting Schedules:
(a) G-2
(b) G-3
(c) D-1
(d) C-5

Southwestern Electric Power Company
Index- B Workpapers
Test Year Ending December 31, 2018
Docket No. 19-008-U

Southwestern Electric Power Company **SCHEDULE B-1**
Derivation of Rate Base
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing derivation of rate base by component

(1) Line No.	(2) Description	(3) Test Year (a)	(4) Pro Forma Adjustments (b)	(5) Pro Forma Year (Col. 3 + Col. 4) (A)
1	Gross Utility Plant in Service at Original Cost (a)	$ 9,198,366,842	$ (1,271,007,299)	$ 7,927,359,543
2	Less: Accumulated Depreciation (a)	3,006,503,342	(131,582,802)	2,874,920,541
3	Net Utility Plant-in-Service	6,191,863,500	(1,139,424,498)	5,052,439,002
4	Plant Held for Future Use (c)	1,291,835	(204,896)	1,086,940
5	Construction Work in Progress (b)	208,464,848	(208,464,848)	-
6	Working Capital Assets (d)	1,198,881,247	(310,103,946)	888,777,301
7	Other -Acquisition Adjustments (e)	-		-
8	Total Rate Base	$ 7,600,501,430	$ (1,658,198,187)	$ 5,942,303,243

Supporting Schedules and Workpapers:
(a) Schedule B-3
(b) Schedule B-2
(c) Schedule B-7
(d) Schedule B-4
(e) Schedule B-10

Recap Schedules
(A) Schedule G-2

Southwestern Electric Power Company
Adjustments to Test Year Rate Base
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing pro forma adjustments to test year original cost or projected cost rate base detailed by adjustment

(1) Line No.	(2) Account	(3) Description	(4) Adjustment No. RB-1 (c) Jurisdictional AFUDC & Depr. Rate	(5) Adjustment No. RB-2 (d) Jurisdictional AFUDC Equity	(6) Adjustment No. RB-3 (e) 2019 Plant in Service	(7) Adjustment No. RB-4 (f) 2019 Accumulated Depreciation
		PLANT IN SERVICE				
		INTANGIBLE PLANT				
1	301	Organization	-	-	-	-
2	302	Franchise and Consents				-
3	303	Miscellaneous Intangible Plant			27,726,556	
4		Reclassed Intangible CWIP In-service at Pro-forma Year End				
5		TOTAL INTANGIBLE PLANT	-	-	27,726,556	-
6		PRODUCTION PLANT				
7		STEAM PRODUCTION				
8	310	Land and Land Rights	-		-	-
9	311	Structures and Improvement	-		3,856,173	-
10	312	Boiler Plant Equipment	-		20,831,571	-
11	314	Turbogenerator Units	-		3,142,200	-
12	315	Accessory Electric Equipment	-		1,781,756	-
13	316	Miscellaneous Power Plant Equipment	-		1,591,989	-
	317	ARO Steam Production Plant			-	
		Jurisdictional AFUDC	47,308,009	(3,165,524)		
		Reclassed Generation CWIP In-service at Pro-forma Year End				
14		TOTAL STEAM PRODUCTION	$ 47,308,009	$ (3,165,524)	$ 31,203,689	$ -
15		OTHER PRODUCTION				
16	340	Land and Land Rights	-	-	-	-
17	341	Structures and Improvement	-		241,206	-
18	342	Fuel Holders, Products, and Accessories	-		-	-
19	343	Prime movers	-		-	-
20	344	Generators	-		580,402	-
21	345	Accessory Electric Equipment	-		62,143	-
22	346	Miscellaneous Power Plant Equipment	-		5,420	-
23	347	ARO Cost for Other Production	-	-	-	-
24		TOTAL OTHER PRODUCTION	-	-	889,171	-
25		TOTAL PRODUCTION PLANT	$ 47,308,009	$ (3,165,524)	$ 32,092,860	$ -

Supporting Schedules
(a) B-8
(b) B-4
(c) WP B 2-1
(d) WP B 2-2, WP B 2-3
(e) WP B 2-4
(f) WP B 2-6
(g) WP B 2-5, 2-5-1, B-7
(h) E-17B
(i) WP B 2-7

Recap Schedules
B-1

Southwestern Electric Power Company
Adjustments to Test Year Rate Base
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Docket No. 19-008-U

Explanation: Schedule showing pro forma adjustments to test year original cost or projected cost rate base detailed by adjustment

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26		TRANSMISSION PLANT				
27	350	Land and Land Rights	-		8,411,233	
28	352	Structures and Improvements	-		1,337,662	
29	353	Station Equipment	-		56,281,981	
30	354	Towers and Fixtures	-		3,714,814	
31	355	Poles and Fixtures	-		58,836,677	
32	356	Overhead Conductors and Devices	-		34,583,774	
33	357	Underground Conduit			188,069	
34	358	Underground Conductors and Devices	-	-	3,639	-
	359	359 Roads and Trails				
		Jurisdictional AFUDC	2,724,366	(1,854,269)		
35		Reclassed Transmission CWIP In-service at Pro-forma Year End				
36		TOTAL TRANSMISSION PLANT	2,724,366	(1,854,269)	163,357,849	-
37		DISTRIBUTION PLANT				
38	360	Land and Land Rights	-	-	-	-
39	361	Structures and Improvements	-		427,540	-
40	362	Station Equipment	-		16,903,411	-
41	364	Poles, Towers, and Fixtures	-		24,129,818	-
42	365	Overhead Conductors and Devices	-		24,188,485	-
43	366	Underground Conduit	-		3,657,697	-
44	367	Underground Conductors and Devices	-		12,063,318	-
45	368	Line Transformers	-		21,255,667	-
46	369	Services	-		4,998,429	-
47	370	Meters	-		4,639,472	-
48	371	Installations on Customers' Premises	-		2,397,210	-
49	373	Street Lighting and Signal Systems	-		2,302,286	-
50		Jurisdictional AFUDC	-	(3,705,457)		
51		Reclassed Distribution CWIP In-service at Pro-forma Year End				
52		TOTAL DISTRIBUTION PLANT	-	(3,705,457)	116,963,333	-
53		GENERAL PLANT				
54	389	Land and Land Rights	-	-	-	-
55	390	Structures and Improvements	-		(602,199)	-
56	391	Office Furniture and Equipment	-		(399)	-
57	392	Transportation Equipment	-		-	-
58	393	Stores Equipment	-		(17,264)	-
59	394	Tools, Shop and Garage Equipment	-		(151,858)	-
60	395	Laboratory Equipment	-		-	-
61	396	Power Operated Equipment	-		-	-

Supporting Schedules
(a) B-8
(b) B-4
(c) WP B 2-1
(d) WP B 2-2, WP B 2-3
(e) WP B 2-4
(f) WP B 2-6
(g) WP B 2-5, 2-5-1, B-7
(h) E-17B
(i) WP B 2-7

Recap Schedules
B-1

Southwestern Electric Power Company
Adjustments to Test Year Rate Base
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing pro forma adjustments to test year original cost or projected cost rate base detailed by adjustment

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62	397	Communication Equipment	-		(207,162)	-
63	398	Miscellaneous Equipment	-		(14,966)	-
64	399	Other Tangible Property		-	(384,687)	-
65		Jurisdictional AFUDC	2,682,534	(634,282)		
66		TOTAL GENERAL PLANT	$ 2,682,534	$ (634,282)	$ (1,378,535)	$ -
67	101	Holding Company Assets	-		-	-
68		TOTAL COMPANY PLANT IN SERVICE	$ 52,714,909	$ (9,359,532)	$ 338,762,063	$ -
		ACCUMULATED DEPRECIATION				
Line No.	Account	Description				
		INTANGIBLE PLANT				
69	301	Organization	-	-	-	-
70	302	Franchise and Consents	-	-	-	-
71	303	Miscellaneous Intangible Plant	-	-		2,833,735
72		Reclassed Intangible CWIP In-service at Pro-forma Year End				
73		TOTAL INTANGIBLE PLANT	-	-	-	2,833,735
74		PRODUCTION PLANT				
75		STEAM PRODUCTION				
76	310.100	Land	-	-	-	-
77	310.200	Land Rights	-	-	-	-
78	311	Structures and Improvements	-	-		15,538,409
79	312	Boiler Plant Equipment	-	-		46,444,996
80	314	Turbogenerator Units	-	-		13,688,968
81	315	Accessory Electric Equipment	-	-		4,226,940
82	316	Miscellaneous Power Plant Equipment	-	-		4,500,646
83	317	ARO Cost	-	-	-	585,148
84	230	ARO Obligation				
85		Jurisdictional AFUDC	$ 46,668,799	(3,420,909)		
		Reclassed Generation CWIP In-service at Pro-forma Year End				
86		TOTAL STEAM PRODUCTION	46,668,799	(3,420,909)	-	84,985,106
87		OTHER PRODUCTION				

Supporting Schedules
(a) B-8
(b) B-4
(c) WP B 2-1
(d) WP B 2-2, WP B 2-3
(e) WP B 2-4
(f) WP B 2-6
(g) WP B 2-5, 2-5-1, B-7
(h) E-17B
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B-1

Southwestern Electric Power Company
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88	340.100	Land	-	-	-	-
89	340.200	Land Rights	-	-	-	-
90	341	Structures and Improvements	-	-	-	497,722
91	342	Fuel Holders, Producers and Accessories	-	-	-	-
92	343	Prime movers	-	-	-	-
93	344	Generators	-	-	-	1,240,510
94	345	Accessory Electric Equipment	-	-	-	85,425
95	346	Miscellaneous Power Plant Equipment	-	-	-	6,399
96	347	ARO Cost - Other Production	-	-	-	-
97		TOTAL OTHER PRODUCTION	-	-	-	1,830,056
98		TOTAL PRODUCTION PLANT	$ 46,668,799	$ (3,420,909)	$ -	$ 86,815,163
99		TRANSMISSION PLANT				
100	350.100	Land	-	-	-	
101	350.200	Land Rights	-	-	-	1,538,585
102	352	Structures and Improvements	-	-		314,786
103	353	Station Equipment	-	-		9,680,302
104	354	Towers and Fixtures	-	-		1,571,374
105	355	Poles and Fixtures	-	-		9,128,645
106	356	Overhead Conductors and Devices	-	-		7,042,501
107	357	Underground Conduit				730
108	358	Underground Conductors and Devices	-	-	-	32
109	359	ARO - Transmission	-	-	-	5,344
110		Jurisdictional AFUDC	(49,686,987)	(999,638)		
		Reclassed Generation CWIP In-service at Pro-forma Year End				
111		TOTAL TRANSMISSION PLANT	$ (49,686,987)	$ (999,638)	$ -	$ 29,282,299
112		DISTRIBUTION PLANT				
113	360.100	Land	-	-	-	-
114	360.200	Land Rights	-	-	-	133,502
115	361	Structures and Improvements	-	-		133,123
116	362	Station Equipment	-	-		4,924,374
117	364	Poles, Towers, and Fixtures	-	-		10,826,361
118	365	Overhead Conductors and Devices	-	-		8,744,726
119	366	Underground Conduit	-	-		1,429,332
120	367	Underground Conductors and Devices	-	-		5,570,937
121	368	Line Transformers	-	-		6,732,635
122	369	Services	-	-		2,214,367
123	370	Meters	-	-		(2,263,454)

Supporting Schedules
(a) B-8
(b) B-4
(c) WP B 2-1
(d) WP B 2-2, WP B 2-3
(e) WP B 2-4
(f) WP B 2-6
(g) WP B 2-5, 2-5-1, B-7
(h) E-17B
(i) WP B 2-7

Recap Schedules
B-1

Southwestern Electric Power Company
Adjustments to Test Year Rate Base
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing pro forma adjustments to test year original cost or projected cost rate base detailed by adjustment

(1) Line No.	(2) Account	(3) Description	(4) Adjustment No. RB-1 (c) Jurisdictional AFUDC & Depr. Rate	(5) Adjustment No. RB-2 (d) Jurisdictional AFUDC Equity	(6) Adjustment No. RB-3 (e) 2019 Plant in Service	(7) Adjustment No. RB-4 (f) 2019 Accumulated Depreciation
124	371	Installation on Customer Premises	-	-	-	1,420,418
125	373	Street Lighting and Signal Systems	-	-	-	1,446,763
126		Jurisdictional AFUDC	(175,869,338)	(1,975,565)		
		Reclassed Generation CWIP In-service at Pro-forma Year End				
127		TOTAL DISTRIBUTION PLANT	$ (175,869,338)	$ (1,975,565)	$ -	$ 41,313,084
128		GENERAL PLANT				
129	389.100	Land	-	-	-	-
130	389.200	Land Rights	-	-	-	(10,890)
131	390	Structures and Improvements	-	-		2,419,318
132	391	Office Furniture and Equipment	-	-		232,763
133	392	Transportation Equipment	-	-		206,737
134	393	Stores Equipment	-	-		96,211
135	394	Tools, Shop and Garage Equipment	-	-		504,734
136	395	Laboratory Equipment	-	-		90,510
137	396	Power Operated Equipment	-	-		1,722
138	397	Communication Equipment	-	-		936,252
139	398	Miscellaneous Equipment	-	-		69,921
140	399	Other Tangible Property	-	-	-	4,024,668
141		Jurisdictional AFUDC	(17,817,254)	(502,809)		
142		TOTAL GENERAL PLANT	$ (17,817,254)	$ (502,809)	$ -	$ 8,571,946
143		TOTAL ACCUMULATED DEPRECIATION	$ (196,704,780)	$ (6,898,921)	$ -	$ 168,816,227
144	105	**PLANT HELD FOR FUTURE USE**	-			

Supporting Schedules
(a) B-8
(b) B-4
(c) WP B 2-1
(d) WP B 2-2, WP B 2-3
(e) WP B 2-4
(f) WP B 2-6
(g) WP B 2-5, 2-5-1, B-7
(h) E-17B
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Recap Schedules
B-1

Southwestern Electric Power Company
Adjustments to Test Year Rate Base
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing pro forma adjustments to test year original cost or projected cost rate base detailed by adjustment

(1) Line No.	(2) Account	(3) Description	(4) Adjustment No. RB-1 (c) Jurisdictional AFUDC & Depr. Rate	(5) Adjustment No. RB-2 (d) Jurisdictional AFUDC Equity	(6) Adjustment No. RB-3 (e) 2019 Plant in Service	(7) Adjustment No. RB-4 (f) 2019 Accumulated Depreciation
145	107	**CONSTRUCTION WORK IN PROGRESS**	-			
146		Production	-		-	-
147		Transmission	-		-	-
148		Distribution	-		-	-
149		General	-		-	-
150		Intangible Plant	-		-	-
151		TOTAL CWIP	-	-	-	-
152		**WORKING CAPITAL ASSETS**				
153		**Total Rate Base Adjustments**	$ 249,419,689	$ (2,460,611)	$ 338,762,063	$ (168,816,227)

Supporting Schedules
(a) B-8
(b) B-4
(c) WP B 2-1
(d) WP B 2-2, WP B 2-3
(e) WP B 2-4
(f) WP B 2-6
(g) WP B 2-5, 2-5-1, B-7
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Recap Schedules
B-1

Southwestern Electric Power Company
Adjustments to Test Year Rate Base
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing pro forma adjustments to test year original cost or projected cost rate base detailed by adjustment

(1) Line No.	(2) Account	(3) Description	(8) Adjustment No. RB-5(b) Working Capital	(9) Adjustment No. RB-6(g) Turk	(10) Adjustment No. RB-7(h) Reclass ARO Obligation	(12) Adjustment No. RB-8(a) Remove CWIP	(13) Adjustment No. RB-9 (h) Incremental Plant	(14) Total Pro Forma Adjustments
		PLANT IN SERVICE						
		INTANGIBLE PLANT						
1	301	Organization	-	-	-	-	-	-
2	302	Franchise and Consents	-	-	-	-	-	-
3	303	Miscellaneous Intangible Plant	-	-	-	-	-	27,726,556
4		Reclassed Intangible CWIP In-service at Pro-forma Ye					7,584,352	7,584,352
5		TOTAL INTANGIBLE PLANT	-	-	-	-	7,584,352	35,310,908
6		PRODUCTION PLANT						
7		STEAM PRODUCTION						
8	310	Land and Land Rights	-	(13,355,616)	-	-	-	(13,355,616)
9	311	Structures and Improvement	-	(290,798,952)	-	-	-	(286,942,779)
10	312	Boiler Plant Equipment	-	(1,004,352,733)	-	-	-	(983,521,162)
11	314	Turbogenerator Units	-	(232,599,492)	-	-	-	(229,457,292)
12	315	Accessory Electric Equipment	-	(95,054,977)	-	-	-	(93,273,221)
13	316	Miscellaneous Power Plant Equipment	-	(48,892,754)	-	-	-	(47,300,765)
	317	ARO Steam Production Plant		(2,179,313)				(2,179,313)
		Jurisdictional AFUDC						44,142,485
		Reclassed Generation CWIP In-service at Pro-forma Y					14,439,547	14,439,547
14		TOTAL STEAM PRODUCTION	$ -	$ (1,687,233,837)	$ -	$ -	$ 14,439,547	$ (1,597,448,116)
15		OTHER PRODUCTION						
16	340	Land and Land Rights	-	-	-	-	-	-
17	341	Structures and Improvement	-	-	-	-	-	241,206
18	342	Fuel Holders, Products, and Accessories	-	-	-	-	-	-
19	343	Prime movers	-	-	-	-	-	-
20	344	Generators	-	-	-	-	-	580,402
21	345	Accessory Electric Equipment	-	-	-	-	-	62,143
22	346	Miscellaneous Power Plant Equipment	-	-	-	-	-	5,420
23	347	ARO Cost for Other Production	-	-	-	-	-	-
24		TOTAL OTHER PRODUCTION	-	-	-	-	-	$889,171
25		TOTAL PRODUCTION PLANT	$ -	$ (1,687,233,837)	$ -	$ -	$ 14,439,547	$ (1,596,558,945)

Supporting Schedules
(a) B-8
(b) B-4
(c) WP B 2-1
(d) WP B 2-2, WP B 2-3
(e) WP B 2-4
(f) WP B 2-6
(g) WP B 2-5, 2-5-1, B-7
(h) E-17B
(i) WP B 2-7

Recap Schedules
B-1

Southwestern Electric Power Company
Adjustments to Test Year Rate Base
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing pro forma adjustments to test year original cost or projected cost rate base detailed by adjustment

(1) Line No.	(2) Account	(3) Description	(8) Adjustment No. RB-5(b) Working Capital	(9) Adjustment No. RB-6(g) Turk	(10) Adjustment No. RB-7(h) Reclass ARO Obligation	(12) Adjustment No. RB-8(a) Remove CWIP	(13) Adjustment No. RB-9 (h) Incremental Plant	(14) Total Pro Forma Adjustments
26		TRANSMISSION PLANT						
27	350	Land and Land Rights	-	-	-	-	-	8,411,233
28	352	Structures and Improvements	-	-	-	-	-	1,337,662
29	353	Station Equipment	-	(8,099,658)	-	-	-	48,182,323
30	354	Towers and Fixtures		-	-	-	-	3,714,814
31	355	Poles and Fixtures		-	-	-	-	58,836,677
32	356	Overhead Conductors and Devices	-	-	-	-	-	34,583,774
33	357	Underground Conduit						188,069
34	358	Underground Conductors and Devices	-	-	-	-	-	3,639
	359	359 Roads and Trails						-
		Jurisdictional AFUDC						870,097
35		Reclassed Transmission CWIP In-service at Pro-forma					16,184,668	16,184,668
36		TOTAL TRANSMISSION PLANT	-	(8,099,658)	-	-	16,184,668	172,312,956
37		DISTRIBUTION PLANT						
38	360	Land and Land Rights	-	-	-	-	-	-
39	361	Structures and Improvements	-	-	-	-	-	427,540
40	362	Station Equipment	-	-	-	-	-	16,903,411
41	364	Poles, Towers, and Fixtures	-	-	-	-	-	24,129,818
42	365	Overhead Conductors and Devices	-	-	-	-	-	24,188,485
43	366	Underground Conduit	-	-	-	-	-	3,657,697
44	367	Underground Conductors and Devices	-	-	-	-	-	12,063,318
45	368	Line Transformers	-	-	-	-	-	21,255,667
46	369	Services	-	-	-	-	-	4,998,429
47	370	Meters	-	-	-	-	-	4,639,472
48	371	Installations on Customers' Premises	-	-	-	-	-	2,397,210
49	373	Street Lighting and Signal Systems	-	-	-	-	-	2,302,286
50		Jurisdictional AFUDC						(3,705,457)
51		Reclassed Distribution CWIP In-service at Pro-forma Y					4,000,189	4,000,189
52		TOTAL DISTRIBUTION PLANT	-	-	-	-	4,000,189	117,258,065
53		GENERAL PLANT						
54	389	Land and Land Rights	-	-	-	-	-	0
55	390	Structures and Improvements	-	-	-	-	-	(602,199)
56	391	Office Furniture and Equipment	-	-	-	-	-	(399)
57	392	Transportation Equipment	-	-	-	-	-	0
58	393	Stores Equipment	-	-	-	-	-	(17,264)
59	394	Tools, Shop and Garage Equipment	-	-	-	-	-	(151,858)
60	395	Laboratory Equipment	-	-	-	-	-	0
61	396	Power Operated Equipment	-	-	-	-	-	0

Supporting Schedules
(a) B-8
(b) B-4
(c) WP B 2-1
(d) WP B 2-2, WP B 2-3
(e) WP B 2-4
(f) WP B 2-6
(g) WP B 2-5, 2-5-1, B-7
(h) E-17B
(i) WP B 2-7

Recap Schedules
B-1

Southwestern Electric Power Company
Adjustments to Test Year Rate Base
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing pro forma adjustments to test year original cost or projected cost rate base detailed by adjustment

(1) Line No.	(2) Account	(3) Description	(8) Adjustment No. RB-5(b) Working Capital	(9) Adjustment No. RB-6(g) Turk	(10) Adjustment No. RB-7(h) Reclass ARO Obligation	(12) Adjustment No. RB-8(a) Remove CWIP	(13) Adjustment No. RB-9 (h) Incremental Plant	(14) Total Pro Forma Adjustments
62	397	Communication Equipment	-	-	-	-	-	(207,162)
63	398	Miscellaneous Equipment	-	-	-	-	-	(14,966)
64	399	Other Tangible Property	-	-	-	-	-	(384,687)
65		Jurisdictional AFUDC						2,048,252
66		TOTAL GENERAL PLANT	$ -	$ -	$ -	$ -	$ -	669,717
67	101	Holding Company Assets	-	-	-		-	0
68		TOTAL COMPANY PLANT IN SERVICE	$ -	$ (1,695,333,495)	$ -	$ -	$ 42,208,756	(1,271,007,299)
		ACCUMULATED DEPRECIATION						
Line No.	Account	Description						
		INTANGIBLE PLANT						
69	301	Organization	-	-	-	-	-	0
70	302	Franchise and Consents	-		-	-	-	0
71	303	Miscellaneous Intangible Plant	-		-	-	-	2,833,735
72		Reclassed Intangible CWIP In-service at Pro-forma Ye					1,442,605	1,442,605
73		TOTAL INTANGIBLE PLANT	-	-	-	-	1,442,605	4,276,340
74		PRODUCTION PLANT						
75		STEAM PRODUCTION						
76	310.100	Land	-					0
77	310.200	Land Rights	-		-	-	-	0
78	311	Structures and Improvements	-	(34,816,214)	-	-	-	(19,277,805)
79	312	Boiler Plant Equipment	-	(124,936,588)	-	-	-	(78,491,592)
80	314	Turbogenerator Units	-	(31,163,099)	-	-	-	(17,474,131)
81	315	Accessory Electric Equipment	-	(11,836,356)	-	-	-	(7,609,416)
82	316	Miscellaneous Power Plant Equipment	-	(5,293,632)	-	-	-	(792,986)
83	317	ARO Cost	-	(312,625)	-	-	-	272,523
84	230	ARO Obligation			109,765,512	-		109,765,512
85		Jurisdictional AFUDC						43,247,890
		Reclassed Generation CWIP In-service at Pro-forma Y					650,903	650,903
86		TOTAL STEAM PRODUCTION	-	(208,358,514)	109,765,512	-	650,903	30,290,897
87		OTHER PRODUCTION						

Supporting Schedules
(a) B-8
(b) B-4
(c) WP B 2-1
(d) WP B 2-2, WP B 2-3
(e) WP B 2-4
(f) WP B 2-6
(g) WP B 2-5, 2-5-1, B-7
(h) E-17B
(i) WP B 2-7

Recap Schedules
B-1

Southwestern Electric Power Company
Adjustments to Test Year Rate Base
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing pro forma adjustments to test year original cost or projected cost rate base detailed by adjustment

(1) Line No.	(2) Account	(3) Description	(8) Adjustment No. RB-5(b) Working Capital	(9) Adjustment No. RB-6(g) Turk	(10) Adjustment No. RB-7(h) Reclass ARO Obligation	(12) Adjustment No. RB-8(a) Remove CWIP	(13) Adjustment No. RB-9 (h) Incremental Plant	(14) Total Pro Forma Adjustments
88	340.100	Land	-					0
89	340.200	Land Rights	-	-				0
90	341	Structures and Improvements	-		-	-	-	497,722
91	342	Fuel Holders, Producers and Accessories	-		-	-	-	0
92	343	Prime movers	-		-	-	-	0
93	344	Generators	-		-	-	-	1,240,510
94	345	Accessory Electric Equipment	-		-	-	-	85,425
95	346	Miscellaneous Power Plant Equipment	-		-	-	-	6,399
96	347	ARO Cost - Other Production	-		-	-	-	0
97		TOTAL OTHER PRODUCTION	$ -	$ -	-	-	-	1,830,056
98		TOTAL PRODUCTION PLANT	$ -	$ (208,358,514)	$ 109,765,512	$ -	$ 650,903	32,120,954
99		TRANSMISSION PLANT						
100	350.100	Land						0
101	350.200	Land Rights	-		-	-	-	1,538,585
102	352	Structures and Improvements	-		-	-	-	314,786
103	353	Station Equipment	-	(1,041,963)	-	-	-	8,638,339
104	354	Towers and Fixtures			-	-	-	1,571,374
105	355	Poles and Fixtures			-	-	-	9,128,645
106	356	Overhead Conductors and Devices	-		-	-	-	7,042,501
107	357	Underground Conduit						730
108	358	Underground Conductors and Devices	-		-	-	-	32
109	359	ARO - Transmission	-		-	-	-	5,344
110		Jurisdictional AFUDC						(50,686,625)
		Reclassed Generation CWIP In-service at Pro-forma Y					565,690	565,690
111		TOTAL TRANSMISSION PLANT	$ -	$ (1,041,963)	$ -	$ -	$ 565,690	(21,880,599)
112		DISTRIBUTION PLANT						
113	360.100	Land	-					0
114	360.200	Land Rights	-		-	-	-	133,502
115	361	Structures and Improvements	-		-	-	-	133,123
116	362	Station Equipment	-		-	-	-	4,924,374
117	364	Poles, Towers, and Fixtures	-		-	-	-	10,826,361
118	365	Overhead Conductors and Devices	-		-	-	-	8,744,726
119	366	Underground Conduit	-		-	-	-	1,429,332
120	367	Underground Conductors and Devices	-		-	-	-	5,570,937
121	368	Line Transformers	-		-	-	-	6,732,635
122	369	Services	-		-	-	-	2,214,367
123	370	Meters	-		-	-	-	(2,263,454)

Supporting Schedules
(a) B-8
(b) B-4
(c) WP B 2-1
(d) WP B 2-2, WP B 2-3
(e) WP B 2-4
(f) WP B 2-6
(g) WP B 2-5, 2-5-1, B-7
(h) E-17B
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Recap Schedules
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Southwestern Electric Power Company
Adjustments to Test Year Rate Base
Test Year Ending December 31, 2018
Docket No. 19-008-U

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(1) Line No.	(2) Account	(3) Description	(8) Adjustment No. RB-5(b) Working Capital	(9) Adjustment No. RB-6(g) Turk	(10) Adjustment No. RB-7(h) Reclass ARO Obligation	(12) Adjustment No. RB-8(a) Remove CWIP	(13) Adjustment No. RB-9 (h) Incremental Plant	(14) Total Pro Forma Adjustments
124	371	Installation on Customer Premises	-		-	-	-	1,420,418
125	373	Street Lighting and Signal Systems	-		-	-	-	1,446,763
126		Jurisdictional AFUDC						(177,844,903)
		Reclassed Generation CWIP In-service at Pro-forma Y					180,439	180,439
127		TOTAL DISTRIBUTION PLANT	$ -	$ -	$ -	$ -	$ 180,439	(136,351,380)
128		GENERAL PLANT						
129	389.100	Land	-					0
130	389.200	Land Rights	-		-	-	-	(10,890)
131	390	Structures and Improvements	-		-	-	-	2,419,318
132	391	Office Furniture and Equipment	-		-	-	-	232,763
133	392	Transportation Equipment	-		-	-	-	206,737
134	393	Stores Equipment	-		-	-	-	96,211
135	394	Tools, Shop and Garage Equipment	-		-	-	-	504,734
136	395	Laboratory Equipment	-		-	-	-	90,510
137	396	Power Operated Equipment	-		-	-	-	1,722
138	397	Communication Equipment	-		-	-	-	936,252
139	398	Miscellaneous Equipment	-		-	-	-	69,921
140	399	Other Tangible Property	-		-	-	-	4,024,668
141		Jurisdictional AFUDC						(18,320,063)
142		TOTAL GENERAL PLANT	$ -	$ -	$ -	$ -	$ -	(9,748,117)
143		TOTAL ACCUMULATED DEPRECIATION	$ -	$ (209,400,477)	$ 109,765,512	$ -	$ 2,839,638	$ (131,582,802)
144	105	**PLANT HELD FOR FUTURE USE**	-	(204,896)			0	(204,896)

Supporting Schedules
(a) B-8
(b) B-4
(c) WP B 2-1
(d) WP B 2-2, WP B 2-3
(e) WP B 2-4
(f) WP B 2-6
(g) WP B 2-5, 2-5-1, B-7
(h) E-17B
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Recap Schedules
B-1

Southwestern Electric Power Company
Adjustments to Test Year Rate Base
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing pro forma adjustments to test year original cost or projected cost rate base detailed by adjustment

(1) Line No.	(2) Account	(3) Description	(8) Adjustment No. RB-5(b) Working Capital	(9) Adjustment No. RB-6(g) Turk	(10) Adjustment No. RB-7(h) Reclass ARO Obligation	(12) Adjustment No. RB-8(a) Remove CWIP	(13) Adjustment No. RB-9 (h) Incremental Plant	(14) Total Pro Forma Adjustments
145	107	**CONSTRUCTION WORK IN PROGRESS**						
						-	-	
146		Production	-			(38,475,598)		(38,475,598)
147		Transmission	-			(115,019,348)		(115,019,348)
148		Distribution	-			(23,531,339)		(23,531,339)
149		General	-			(19,526,357)		(19,526,357)
150		Intangible Plant	-	-		(11,912,206)		(11,912,206)
151		TOTAL CWIP	-	-	-	(208,464,848)	-	(208,464,848)
152		**WORKING CAPITAL ASSETS**	(310,103,946)			-	-	(310,103,946)
153		**Total Rate Base Adjustments**	$ (310,103,946)	$ (1,486,137,914)	$ (109,765,512)	$ (208,464,848)	$ 39,369,118	(1,658,198,187)

Supporting Schedules
(a) B-8
(b) B-4
(c) WP B 2-1
(d) WP B 2-2, WP B 2-3
(e) WP B 2-4
(f) WP B 2-6
(g) WP B 2-5, 2-5-1, B-7
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Recap Schedules
B-1

Southwestern Electric Power Company **WP B 2-1**
Adjustments To Test Year Utility Plant For Jurisdiction AFUDC and Depreciation
Test Year Ending December 31, 2018
Docket No. 19-008-U Increase (Decrease)

TEST YEAR ENDING DECEMBER 31, 2018

	Production	Transmission	Distribution	General	Fuel	Total
Accumulated Depr. Adjustment - Rate Diff	19,461,057	(50,547,174)	(165,677,606)	(19,084,600)	0	(215,848,322)

	Production	Transmission	Distribution	General	Fuel	Total
Plant-In Service Adjustment	48,828,914	2,724,366		34,944	2,647,590	54,235,814
Accum DIT - Prov	10,501,194	814,500		135,545	482,762	
Accum DIT - Writeback	(10,501,194)	(594,897)		(135,545)	(436,630)	
	(0)	219,603	0	0	46,132	265,735
Accum Prov for Depr.	48,828,914	2,237,744		34,944	2,502,737	53,604,339
Rate Base Effect	0	267,020	0	(0)	98,721	365,740

Depreciation Expense Adjustment

Plant	Composite Rate(a)	Plant	Adj to Depreciation Expense
Production	3.01%	51,476,504	1,546,965
Transmission	2.33%	2,724,366	63,482
Distribution			0
General	2.38%	34,944	830
			1,611,277

Summary of Reserve for Depr Adjustment

	Production	Transmission	Distribution	General	Fuel	
Rate Differential Adj.	19,461,057	(50,547,174)	(165,677,606)	(19,084,600)	0	(215,848,322)
AFUDC Differential	48,828,914	2,237,744		34,944	2,502,737	53,604,339
	68,289,971	(48,309,430)	(165,677,606)	(19,049,656)	2,502,737	(162,243,983)

STALL PLANT AFUDC JURISDICTIONAL ADJ.

	2018
STALL PLANT AFUDC ADJUSTMENT- AFUDC Debt & Eq	(1,520,905)
Accumulated Reserve for Depr- AFUDC Debt & Eq	(369,363)
ADIT Adj.	(333,739)
Depreciation Expense Adj	(45,706)

			Composite Rate
Prod.	**3,005,884,854**	**90,332,463**	3.01%
Tran	1,996,113,093	46,512,418	2.33%
General	216,492,121	5,142,896	2.38%

Purpose: To adjust pro-forma year plant balance for jurisdictional AFUDC differences, depreciation reserve differences and related ADIT.
Note: Supporting workpapers provided electronically

Supporting Schedules:	Recap Schedules:
(a) F-1.3	B-2

Southwestern Electric Power Company **WP B 2-1**
Adjustments To Test Year Utility Plant For Jurisdiction AFUDC and Depreciation
Test Year Ending December 31, 2018
Docket No. 19-008-U Increase (Decrease)

PRO FORMA YEAR ENDING DECEMBER 31, 2019

	Production	Transmission	Distribution	General	Fuel	Total
Accumulated Depr. Adjustment - Rate Diff	(1,747,298)	(51,985,320)	(175,869,338)	(20,424,553)	0	(250,026,510)

Plant-In Service Adjustment	48,828,914	2,724,366		34,944	2,647,590	54,235,814
Accum DIT - Prov	10,501,194	814,500		135,545	482,762	
Accum DIT - Writeback	(10,501,194)	(607,621)		(135,545)	(446,377)	
	(0)	206,879	0	0	36,385	243,264
Accum Prov for Depr.	48,828,914	2,298,333		34,944	2,572,355	53,734,547
Rate Base Effect	0	219,154	0	(0)	38,849	258,003

Depreciation Expense Adjustment

Plant	Composite Rate(a)	Plant	Adj to Depreciation Expense
Production	3.01%	51,476,504	1,546,965
Transmission	2.33%	2,724,366	63,482
Distribution			0
General	2.38%	34,944	830
			1,611,277

Summary of Reserve for Depr Adjustment

	Production	Transmission	Distribution	General	Fuel	
Rate Differential Adj.	(1,747,298)	(51,985,320)	(175,869,338)	(20,424,553)	0	(250,026,510)
AFUDC Differential	48,828,914	2,298,333		34,944	2,572,355	53,734,547
	47,081,616	(49,686,987)	(175,869,338)	(20,389,609)	2,572,355	(196,291,963)

STALL PLANT AFUDC JURISDICTIONAL ADJ.

	2019
STALL PLANT AFUDC ADJUSTMENT- AFUDC Debt & Eq	(1,520,905)
Accumulated Reserve for Depr- AFUDC Debt & Eq	(412,817)
ADIT Adj.	(321,145)
Depreciation Expense Adj	(45,706)

			Composite Rate
Prod.	**3,005,884,854**	**90,332,463**	3.01%
Tran	**1,996,113,093**	**46,512,418**	2.33%
General	**216,492,121**	**5,142,896**	2.38%

Purpose: To adjust pro-forma year plant balance for jurisdictional AFUDC differences, depreciation reserve differences and related ADIT.

Supporting Schedules:	Recap Schedules:
(a) F-1.3	B-2

Southwestern Electric Power Company
AFUDC-Equity - Adjustment For Amount Accrued On Books
Test Year Ending December 31, 2018
Docket No. 19-008-U

YEAR	(A) AFUDC EQUITY ACCRUED	(B) AFUDC EQUITY RATE USED	(C) ARKANSAS AFUDC EQUITY RATE	(D) (C) x (A) / (B) AFUDC EQUITY BASED ON ARKANSAS EQUITY RATE	(E) (D) - (A) ADJUSTMENT	PRODUCTION	TRANSMISSION	DISTRIBUTION	GENERAL	TOTAL
1977	3,583,892	4.999500%	4.872100%	3,492,565	(91,327)	(63,555)	(9,780)	(13,571)	(4,420)	(91,326)
1978	3,922,330	4.653000%	4.586100%	3,865,935	(56,395)	(39,246)	(6,039)	(8,380)	(2,730)	(56,395)
1979	5,294,396	4.738000%	4.668900%	5,217,181	(77,215)	(53,735)	(8,269)	(11,474)	(3,737)	(77,215)
1980	6,881,814	5.905300%	5.810100%	6,770,872	(110,942)	(77,206)	(11,880)	(16,486)	(5,370)	(110,942)
1981	8,250,307	6.587000%	6.490200%	8,129,064	(121,243)	(84,375)	(12,983)	(18,017)	(5,868)	(121,243)
1982	7,297,140	6.209400%	6.419600%	7,544,162	247,022	171,906	26,452	36,708	11,956	247,022
1983	16,708,563	6.709200%	6.697900%	16,680,422	(28,141)	(19,584)	(3,014)	(4,182)	(1,362)	(28,142)
1984	30,290,774	7.365300%	6.872300%	28,263,246	(2,027,528)	(1,410,984)	(217,117)	(301,293)	(98,133)	(2,027,527)
1985	19,891,254	6.588000%	6.414200%	19,366,497	(524,757)	(365,186)	(56,193)	(77,980)	(25,399)	(524,758)
1986	7,349,359	6.512800%	6.323500%	7,135,744	(213,615)	(148,658)	(22,875)	(31,744)	(10,339)	(213,616)
1987	949,822	6.964900%	6.680300%	911,010	(38,812)	(3,443)	(4,757)	(19,590)	(11,022)	(38,812)
1988	1,120,047	6.987100%	6.203600%	994,450	(125,597)	(9,252)	(26,130)	(78,956)	(11,259)	(125,597)
1989	163,153	4.588100%	4.054800%	144,189	(18,964)	(1,094)	(3,262)	(12,285)	(2,323)	(18,964)
1990	248,817	3.967900%	3.509000%	220,041	(28,776)	(1,269)	(4,283)	(17,022)	(6,202)	(28,776)
1991	550,127	4.989600%	4.412500%	486,499	(63,628)	(5,200)	(10,106)	(36,375)	(11,946)	(63,627)
1992	132,592	5.763100%	5.096600%	117,258	(15,334)	(1,798)	(2,995)	(6,844)	(3,698)	(15,335)
1993	1,560,064	4.234500%	3.744300%	1,379,466	(180,598)	(10,942)	(10,371)	(120,759)	(38,526)	(180,598)
1994	3,579,028	6.633900%	5.841300%	3,151,416	(427,612)	(30,676)	(121,000)	(191,314)	(84,622)	(427,612)
1995	4,289,918	3.290500%	2.894800%	3,774,033	(515,885)	(39,854)	(202,887)	(231,650)	(41,495)	(515,886)
1996**	325,442	3.290500%	2.894800%	286,306	(39,136)	(3,362)	(6,401)	(13,837)	(15,535)	(39,135)
1997	934,073	1.905700%	1.673600%	820,310	(113,763)	(33,190)	(7,121)	(56,057)	(17,395)	(113,763)
1998	1,335,703	14.780000%	13.000000%	1,174,840	(160,863)	(19,651)	(35,133)	(82,594)	(23,485)	(160,863)
1999	35,592	14.840000%	12.432877%	29,819	(5,773)	(1,282)	(612)	(3,020)	(859)	(5,773)
2000	445,514	13.320000%	10.750000%	359,555	(85,959)	(13,218)	(27,813)	(39,169)	(5,759)	(85,959)
2001	571,968	13.440000%	10.750000%	457,489	(114,479)	(21,148)	(24,772)	(59,838)	(8,721)	(114,479)
2002	(24,273)	14.946700%	10.750000%	(17,458)	6,815	2,200	2,874	1,436	306	6,816
2003	1,100,164	15.700000%	10.750000%	753,297	(346,867)	(64,170)	(101,848)	(162,345)	(18,503)	(346,866)
2004	781,634	15.700000%	10.750000%	535,195	(246,439)	(59,919)	(50,233)	(128,037)	(8,249)	(246,438)
2005	2,394,175	15.700000%	10.750000%	1,639,324	(754,851)	(230,366)	(100,318)	(399,990)	(24,177)	(754,851)
2006	1,302,241	15.700000%	10.750000%	891,662	(410,579)	(166,753)	(51,857)	(183,120)	(8,849)	(410,579)
2007	10,243,611	15.700000%	10.750000%	7,013,937	(3,229,674)	(745,628)	(957,939)	(1,375,441)	(150,665)	(3,229,673)
2008***	2,909,719	12.151400%	10.750000%	2,574,147	(335,573)	(156,449)	(95,413)	(73,213)	(10,497)	(335,573)
2009	2,612,539	11.92127%	10.75000%	2,355,855	(256,684)	(82,632)	(126,359)	(47,534)	(159)	(256,684)
2010	2,492,182	10.90502%	10.25000%	2,342,486	(149,695)	(24,266)	(113,450)	(11,019)	(960)	(149,695)
2011	3,543,896	10.39690%	10.25000%	3,493,825	(50,071)	(14,662)	(29,539)	(5,096)	(775)	(50,071)
2012	5,302,230	10.39690%	10.25000%	5,227,316	(74,914)	(9,520)	(53,633)	(11,116)	(646)	(74,914)
2013	2,348,742	9.97238%	10.25000%	2,414,128	65,386	17,619	34,260	12,925	582	65,386
2014	6,525,057	9.91264%	10.25000%	6,747,127	222,070	93,869	101,182	25,844	1,175	222,070
2015	5,224,745	9.90887%	10.25000%	5,404,618	179,873	86,588	86,422	5,129	1,734	179,873
Jun-16	36,187,576	9.90887%	10.25000%	37,433,413	1,245,837	1,145,715	89,858	6,618	3,646	1,245,837
Jun-17	8,063,167	9.90281%	10.25000%	8,345,863	282,697	40,104	222,308	18,576	1,708	282,697
Jun-18	2,363,090	9.81822%	10.25000%	2,467,014	103,924	23,747	64,133	14,662	1,382	103,924
Total	219,082,184			210,394,118	(8,688,066)	(2,430,524)	(1,888,893)	(3,727,449)	(641,195)	(8,688,062)

** The AFUDC equity rate for 1996 was 0. The accrued AFUDC equity of 325,442 is a prior year true-up. AFUDC equity rates for 1995 are used to determine the 1996 adjustment.
*** Subsequent to 2008 (and per) AR base rate case, changing methodology to calculate and functionalize AFUDC adjustment using 'AFUDC Closed to PIS'.

Southwestern Electric Power Company **WP B 2-2**
AFUDC-Equity - Adjustment For Amount Accrued On Books
Test Year Ending December 31, 2018
Docket No. 19-008-U
SWEPCO
CALCULATION OF AFUDC EQUITY ADJ. ON EQUITY COMPONENT
OF ORIGINAL AFUDC ADJUSTMENT

YEAR	(A) AFUDC EQUITY ACCRUED	(B) AFUDC EQUITY RATE USED	(C) ARKANSAS AFUDC EQUITY RATE	(D) (C) x (A) / (B) AFUDC EQUITY BASED ON ARKANSAS EQUITY RATE	(E) (D) - (A) ADJUSTMENT	PRODUCTION	TRANSMISSION	DISTRIBUTION	GENERAL	TOTAL
1980	699,981	5.905300%	5.810100%	688,697	(11,284)	(8,769)	(2,461)	0	(55)	(11,285)
1981	3,083,447	6.587000%	6.490200%	3,038,134	(45,313)	(42,531)	(2,514)	0	(268)	(45,313)
1982	4,107,386	6.209400%	6.419600%	4,246,429	139,043	136,680	1,692	0	672	139,044
1983	7,517,120	6.709200%	6.697900%	7,504,459	(12,661)	(12,418)	(225)	0	(17)	(12,660)
1984	12,053,798	7.365300%	6.872300%	11,246,971	(806,827)	(786,781)	(19,867)	0	(179)	(806,827)
1985	1,957,560	6.588000%	6.414200%	1,905,917	(51,643)	(46,166)	(5,452)	0	(26)	(51,644)
1986	573,291	6.512800%	6.323500%	556,628	(16,663)	(11,741)	(4,838)	0	(84)	(16,663)
1987	180,040	6.964900%	6.680300%	172,683	(7,357)	(73)	(7,274)	0	(10)	(7,357)
1988	200,633	6.987100%	6.203600%	178,135	(22,498)	(38)	(22,460)	0	0	(22,498)
1989	2,914	4.588100%	4.054800%	2,575	(339)	0	(339)	0	0	(339)
1990	3,914	3.967900%	3.509000%	3,461	(453)	0	(436)	0	(16)	(452)
1991	9,161	4.989600%	4.412500%	8,101	(1,060)	(10)	(927)	0	(122)	(1,059)
1992	17,880	5.763100%	5.096600%	15,812	(2,068)	(37)	(1,191)	0	(840)	(2,068)
1993	(61,402)	4.234500%	3.744300%	(54,294)	7,108	668	2,945	0	3,495	7,108
1994	(38,977)	6.633900%	5.841300%	(34,320)	4,657	595	1,772	0	2,290	4,657
1995	0	3.290500%	2.894800%	0	0	0	0	0	0	0
1996	0	3.290500%	2.894800%	0	0	0	0	0	0	0
1997	0	1.905700%	1.673600%	0	0	0	0	0	0	0
Total	30,306,746			29,479,389	(827,357)	(770,621)	(61,575)	0	4,840	(827,356)

SUMMARY	ORIGINAL AFUDC ADJ. AMT.	PROD.	TRANS.	GEN.
1980	699,981	77.7050%	21.8119%	0.4832%
1981	3,083,447	93.8602%	5.5491%	0.5906%
1982	4,107,386	98.3004%	1.2167%	0.4830%
1983	7,517,120	98.0862%	1.7797%	0.1341%
1984	12,053,798	97.5155%	2.4624%	0.0221%
1985	1,957,560	89.3937%	10.5568%	0.0495%
1986	573,291	70.4585%	29.0348%	0.5067%
1987	180,040	0.9887%	98.8730%	0.1383%
1988	200,633	0.1675%	99.8325%	0.0000%
1989	2,914	0.0000%	100.0000%	0.0000%
1990	3,914	0.0766%	96.4231%	3.5003%
1991	9,161	0.9497%	87.4904%	11.5599%
1992	17,880	1.7841%	57.6174%	40.5984%
1993	(61,402)	9.3955%	41.4319%	49.1727%
1994	(38,977)	12.7742%	38.0558%	49.1700%
1995	0			
1996	0			
1997	0			
Total	30,306,746			

Southwestern Electric Power Company
AFUDC-Equity - Adjustment For Amount Accrued On Books
Test Year Ending December 31, 2018
Docket No. 19-008-U
SWEPCO
SUMMARY OF AFUDC EQUITY ADJUSTMENT(a)

YEAR	PRODUCTION	TRANS.	DISTR.	GENERAL	TOTAL
1977	(63,555)	(9,780)	(13,571)	(4,420)	(91,326)
1978	(39,246)	(6,039)	(8,380)	(2,730)	(56,395)
1979	(53,735)	(8,269)	(11,474)	(3,737)	(77,215)
1980	(85,975)	(14,341)	(16,486)	(5,425)	(122,227)
1981	(126,906)	(15,497)	(18,017)	(6,136)	(166,556)
1982	308,586	28,144	36,708	12,628	386,066
1983	(32,002)	(3,239)	(4,182)	(1,379)	(40,802)
1984	(2,197,765)	(236,984)	(301,293)	(98,312)	(2,834,354)
1985	(411,352)	(61,645)	(77,980)	(25,425)	(576,402)
1986	(160,399)	(27,713)	(31,744)	(10,423)	(230,279)
1987	(3,516)	(12,031)	(19,590)	(11,032)	(46,169)
1988	(9,290)	(48,590)	(78,956)	(11,259)	(148,095)
1989	(1,094)	(3,601)	(12,285)	(2,323)	(19,303)
1990	(1,269)	(4,719)	(17,022)	(6,218)	(29,228)
1991	(5,210)	(11,033)	(36,375)	(12,068)	(64,686)
1992	(1,835)	(4,186)	(6,844)	(4,538)	(17,403)
1993	(10,274)	(7,426)	(120,759)	(35,031)	(173,490)
1994	(30,081)	(119,228)	(191,314)	(82,332)	(422,955)
1995	(39,854)	(202,887)	(231,650)	(41,495)	(515,886)
1996	(3,362)	(6,401)	(13,837)	(15,535)	(39,135)
1997	(33,190)	(7,121)	(56,057)	(17,395)	(113,763)
1998	(19,651)	(35,133)	(82,594)	(23,485)	(160,863)
1999	(1,282)	(612)	(3,020)	(859)	(5,773)
2000	(13,218)	(27,813)	(39,169)	(5,759)	(85,959)
2001	(21,148)	(24,772)	(59,838)	(8,721)	(114,479)
2002	2,200	2,874	1,436	306	6,816
2003	(64,170)	(101,848)	(162,345)	(18,503)	(346,866)
2004	(59,919)	(50,233)	(128,037)	(8,249)	(246,438)
2005	(230,366)	(100,318)	(399,990)	(24,177)	(754,851)
2006	(166,753)	(51,857)	(183,120)	(8,849)	(410,579)
2007	(745,628)	(957,939)	(1,375,441)	(150,665)	(3,229,673)
2008	(156,449)	(95,413)	(73,213)	(10,497)	(335,573)
2009	(82,632)	(126,359)	(47,534)	(159)	(256,684)
2010	(24,266)	(113,450)	(11,019)	(960)	(149,695)
2011	(14,662)	(29,539)	(5,096)	(775)	(50,071)
2012	(9,520)	(53,633)	(11,116)	(646)	(74,914)
2013	17,619	34,260	12,925	582	65,386
2014	93,869	101,182	25,844	1,175	222,070
2015	86,588	86,422	5,129	1,734	179,873
Jun-16	1,145,715	89,858	6,618	3,646	1,245,837
Jun-17	40,104	222,308	18,576	1,708	282,697
Jun-18	23,747	64,133	14,662	1,382	103,924
Total	(3,201,145)	(1,950,468)	(3,727,449)	(636,355)	(9,515,418)
	Forecasted estimates below				
July 2018 Balanc	(3,199,166)	(1,945,124)	(3,726,228)	(636,240)	(9,506,758)
Aug-Dec 2018	9,895	26,722	6,109	576	43,302
12/31/2018	(3,189,272)	(1,918,402)	(3,720,118)	(635,664)	(9,463,456)
Jan - Dec 2019	23,747	64,133	14,662	1,382	103,924
12/31/2019	(3,165,524)	(1,854,269)	(3,705,457)	(634,282)	(9,359,532)

Purpose: To adjust pro-forma year plant balance for jurisdictional equity AFUDC differences

Supporting Schedules:
(a) WP B 2-3

Recap Schedules:
B-2

Southwestern Electric Power Company **WP B 2-3**
AFUDC - Equity Adj. - Accumulated Depreciation
Test Year Ending December 31, 2018
Docket No. 19-008-U

PRODUCTION YEAR	ADJ. AMT.	ANNUAL DEPR. RATE	NO. OF YEARS	DEPR. PROV.	TRANSMISSION YEAR	ADJ. AMT.	ANNUAL DEPR. RATE	NO. OF YEARS	DEPR. PROV.
1977	(63,555)	3.4400%	0.5	(1,093)	1977	(9,780)	2.2900%	0.5	(112)
ACCUM.	(63,555)	3.4400%			ACCUM.	(9,780)			
1978	(39,246)	3.4400%	0.5	(675)	1978	(6,039)	2.2900%	0.5	(69)
ACCUM.	(102,801)	3.4400%	1	(2,186)	ACCUM.	(15,819)	2.2900%	1	(224)
1979	(53,735)	3.4400%	0.5	(924)	1979	(8,269)	2.2900%	0.5	(95)
ACCUM.	(156,536)	3.4400%	1	(3,536)	ACCUM.	(24,088)	2.2900%	1	(362)
1980	(85,975)	3.4400%	0.5	(1,479)	1980	(14,341)	2.2900%	0.5	(164)
ACCUM.	(242,511)	3.4400%	1	(5,385)	ACCUM.	(38,429)	2.2900%	1	(552)
1981	(126,906)	3.8700%	0.5	(2,456)	1981	(15,497)	2.5100%	0.5	(194)
ACCUM.	(369,417)	3.8700%	1	(9,385)	ACCUM.	(53,926)	2.5100%	1	(965)
1982	308,586	3.8700%	0.5	5,971	1982	28,144	1.9500%	0.5	274
ACCUM.	(60,831)	3.4100%	1	(12,597)	ACCUM.	(25,782)	1.9500%	1	(1,052)
1983	(32,002)	3.4100%	0.5	(546)	1983	(3,239)	1.9500%	0.5	(32)
ACCUM.	(92,833)	3.4300%	1	(2,087)	ACCUM.	(29,021)	1.9500%	1	(503)
1984	(2,197,765)	3.4300%	0.5	(37,692)	1984	(236,984)	2.2300%	0.5	(2,642)
ACCUM.	(2,290,598)	3.4300%	1	(3,184)	ACCUM.	(266,005)	2.2300%	1	(647)
1985	(411,352)	3.4300%	0.5	(7,055)	1985	(61,645)	2.2200%	0.5	(684)
ACCUM.	(2,701,950)	3.3000%	1	(75,590)	ACCUM.	(327,650)	2.2200%	1	(5,905)
1986	(160,399)	3.3000%	0.5	(2,647)	1986	(27,713)	2.2200%	0.5	(308)
ACCUM.	(2,862,349)	3.3800%	1	(91,326)	ACCUM.	(355,363)	2.2200%	1	(7,274)
1987	(3,516)	3.3800%	0.5	(59)	1987	(12,031)	2.2200%	0.5	(134)
ACCUM.	(2,865,865)	3.3900%	1	(97,034)	ACCUM.	(367,394)	2.2200%	1	(7,889)
1988	(9,290)	3.3900%	0.5	(157)	1988	(48,590)	2.2200%	0.5	(539)
ACCUM.	(2,875,155)	3.4000%	1	(97,439)	ACCUM.	(415,984)	2.2200%	1	(8,156)
1989	(1,094)	3.4000%	0.5	(19)	1989	(3,601)	2.2200%	0.5	(40)
ACCUM.	(2,876,249)	3.4000%	1	(97,755)	ACCUM.	(419,585)	2.2200%	1	(9,235)
1990	(1,269)	3.4000%	0.5	(22)	1990	(4,719)	2.2200%	0.5	(52)
ACCUM.	(2,877,518)	3.4000%	1	(97,792)	ACCUM.	(424,304)	2.2200%	1	(9,315)
1991	(5,210)	3.4000%	0.5	(89)	1991	(11,033)	2.2300%	0.5	(123)
ACCUM.	(2,882,728)	3.4000%	1	(97,836)	ACCUM.	(435,337)	2.2300%	1	(9,462)
1992	(1,835)	3.4000%	0.5	(31)	1992	(4,186)	2.2400%	0.5	(47)
ACCUM.	(2,884,563)	3.4000%	1	(98,013)	ACCUM.	(439,523)	2.2400%	1	(9,752)
1993	(10,274)	3.4000%	0.5	(175)	1993	(7,426)	2.2400%	0.5	(83)
ACCUM.	(2,894,837)	3.4000%	1	(98,075)	ACCUM.	(446,949)	2.2400%	1	(9,845)
1994	(30,081)	3.4000%	0.5	(511)	1994	(119,228)	2.2500%	0.5	(1,341)
ACCUM.	(2,924,918)	3.4000%	1	(98,424)	ACCUM.	(566,177)	2.2500%	1	(10,056)
1995	(39,854)	3.4000%	0.5	(678)	1995	(202,887)	2.2400%	0.5	(2,272)
ACCUM.	(2,964,772)	3.4000%	1	(99,447)	ACCUM.	(769,064)	2.2400%	1	(12,682)

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1996	(3,362)	3.4000%	0.5	(57)	1996	(6,401)	2.2400%	0.5	(72)
ACCUM.	(2,968,134)	3.4000%	1	(100,802)	ACCUM.	(775,465)	2.2400%	1	(17,227)
1997	(33,190)	3.4200%	0.5	(568)	1997	(7,121)	2.2300%	1	(159)
ACCUM.	(3,001,324)	3.4200%	1	(101,510)	ACCUM.	(782,586)	2.2300%	1.5	(25,939)
1998	(19,651)	3.4200%	0.5	(336)	1998	(35,133)	2.2300%	0.5	(392)
ACCUM.	(3,020,975)	3.4200%	1	(102,645)	ACCUM.	(817,719)	2.2300%	1	(17,452)
1999	(1,282)	3.4200%	0.5	(22)	1999	(612)	2.2300%	0.5	(7)
ACCUM.	(3,022,257)	3.4200%	1	(103,317)	ACCUM.	(818,331)	2.2300%	1	(18,235)
2000	(13,218)	3.4200%	0.5	(226)	2000	(27,813)	2.2300%	0.5	(310)
ACCUM.	(3,035,475)	3.4200%	1	(103,361)	ACCUM.	(846,144)	2.2300%	1	(18,249)
2001	(21,148)	3.4200%	0.5	(362)	2001	(24,772)	2.2300%	0.5	(276)
ACCUM.	(3,056,623)	3.4200%	1	(103,813)	ACCUM.	(870,916)	2.2300%	1	(18,869)
2002	2,200	3.4200%	0.5	38	2002	2,874	2.2300%	0.5	32
ACCUM.	(3,054,423)	3.4200%	1	(104,536)	ACCUM.	(868,042)	2.2300%	1	(19,421)
2003	(64,170)	3.4200%	0.5	(1,097)	2003	(101,848)	2.2300%	0.5	(1,136)
ACCUM.	(3,118,593)	3.4200%	1	(104,461)	ACCUM.	(969,890)	2.2300%	1	(19,357)
2004	(59,919)	3.4200%	0.5	(1,025)	2004	(50,233)	2.2300%	0.5	(560)
ACCUM.	(3,178,512)	3.4200%	1	(106,656)	ACCUM.	(1,020,123)	2.2300%	1	(21,629)
2005	(230,366)	3.4200%	0.5	(3,939)	2005	(100,318)	2.2300%	0.5	(1,119)
ACCUM.	(3,408,878)	3.4200%	1	(108,705)	ACCUM.	(1,120,441)	2.2300%	1	(22,749)
2006	(166,753)	3.4200%	0.5	(2,851)	2006	(51,857)	2.2300%	0.5	(578)
ACCUM.	(3,575,631)	3.4200%	1	(116,584)	ACCUM.	(1,172,298)	2.2300%	1	(24,986)
2007	(745,628)	3.4200%	0.5	(12,750)	2007	(957,939)	2.2300%	0.5	(10,681)
ACCUM.	(4,321,259)	3.4200%	1	(122,287)	ACCUM.	(2,130,237)	2.2300%	1	(26,142)
2008	(156,449)	3.4200%	0.5	(2,675)	2008	(95,413)	2.2300%	0.5	(1,064)
ACCUM.	(4,477,708)	3.4200%	1	(147,787)	ACCUM.	(2,225,650)	2.2300%	1	(47,504)
2009	(82,632)	3.5810%	0.5	(1,480)	2009	(126,359)	2.4116%	0.5	(1,524)
ACCUM.	(4,560,340)	3.5810%	1	(160,347)	ACCUM.	(2,352,009)	2.4116%	1	(53,674)
2010	(24,266)	1.3729%	0.5	(167)	2010	(113,450)	2.1368%	0.5	(1,212)
ACCUM.	(4,584,606)	1.3729%	1	(62,609)	ACCUM.	(2,465,459)	2.1368%	1	(50,258)
2011	(14,662)	1.6456%	0.5	(121)	2011	(29,539)	2.1679%	0.5	(320)
ACCUM.	(4,599,268)	1.6456%	1	(75,444)	ACCUM.	(2,494,998)	2.1679%	1	(53,449)
2012	(9,520)	1.6510%	0.5	(79)	2012	(53,633)	2.1223%	0.5	(569)
ACCUM.	(4,608,788)	1.6510%	1	(75,933)	ACCUM.	(2,548,630)	2.1223%	1	(52,951)
2013	17,619	1.6398%	0.5	144	2013	34,260	2.1906%	0.5	375
ACCUM.	(4,591,169)	1.6398%	1	(75,575)	ACCUM.	(2,514,370)	2.1906%	1	(55,830)
2014	93,869	1.5422%	0.5	724	2014	101,182	2.1450%	0.5	1,085
ACCUM.	(4,497,300)	1.5422%	1	(70,806)	ACCUM.	(2,413,189)	2.1450%	1	(53,933)
2015	86,588	1.6079%	0.5	696	2015	86,422	2.0831%	0.5	900
ACCUM.	(4,410,712)	1.6079%	1	(72,313)	ACCUM.	(2,326,767)	2.0831%	1	(50,270)
2016	1,145,715	1.5146%	0.5	8,677	2016	89,858	2.1356%	0.5	960

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ACCUM.	(3,264,997)	1.5146%	1	(66,806)	ACCUM.	(2,236,909)	2.1356%	1	(49,691)
2017	40,104	1.5935%	0.5	320	2017	222,308	2.1556%	0.5	2,396
ACCUM.	(3,224,893)	1.5935%	1	(52,028)	ACCUM.	(2,014,601)	2.1556%	1	(48,219)
201806	23,747	1.5935%	0.5	189	201806	64,133	2.1556%	0.5	691
ACCUM.	(3,201,145)	1.5935%	1	(51,389)	ACCUM.	(1,950,468)	2.1556%	1	(43,427)
Ending Balance	(3,201,145)			(3,344,109)		(1,950,468)			(935,534)

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GENERAL YEAR	ADJ. AMT.	ANNUAL DEPR. RATE	NO. OF YEARS	DEPR. PROV	**DISTRIBUTION** YEAR	ADJ. AMT.	ANNUAL DEPR. RATE	NO. OF YEARS	DEPR. PROV
1977	(4,420)	2.6900%	0.5	(59)	1977	(13,571)	3.2700%	0.5	(222)
ACCUM.	(4,420)				ACCUM.	(13,571)			
1978	(2,730)	2.6900%	0.5	(37)	1978	(8,380)	3.2700%	0.5	(137)
ACCUM.	(7,150)	2.6900%	1	(119)	ACCUM.	(21,951)	3.2700%	1	(444)
1979	(3,737)	2.6900%	0.5	(50)	1979	(11,474)	3.2700%	0.5	(188)
ACCUM.	(10,887)	2.6900%	1	(192)	ACCUM.	(33,425)	3.2700%	1	(718)
1980	(5,425)	2.6900%	0.5	(73)	1980	(16,486)	3.2700%	0.5	(270)
ACCUM.	(16,312)	2.6900%	1	(293)	ACCUM.	(49,911)	3.2700%	1	(1,093)
1981	(6,136)	2.8900%	0.5	(89)	1981	(18,017)	2.3600%	0.5	(213)
ACCUM.	(22,448)	2.8900%	1	(471)	ACCUM.	(67,928)	2.3600%	1	(1,178)
1982	12,628	2.5600%	0.5	162	1982	36,708	2.3600%	0.5	433
ACCUM.	(9,820)	2.5600%	1	(575)	ACCUM.	(31,220)	2.3600%	1	(1,603)
1983	(1,379)	2.5000%	0.5	(17)	1983	(4,182)	2.3600%	0.5	(49)
ACCUM.	(11,199)	2.5000%	1	(246)	ACCUM.	(35,402)	2.3600%	1	(737)
1984	(98,312)	2.8900%	0.5	(1,421)	1984	(301,293)	2.3600%	0.5	(3,555)
ACCUM.	(109,511)	2.8900%	1	(324)	ACCUM.	(336,695)	2.3600%	1	(835)
1985	(25,425)	2.9600%	0.5	(376)	1985	(77,980)	2.3600%	0.5	(920)
ACCUM.	(134,936)	2.9600%	1	(3,242)	ACCUM.	(414,675)	2.3600%	1	(7,946)
1986	(10,423)	2.9900%	0.5	(156)	1986	(31,744)	3.6400%	0.5	(578)
ACCUM.	(145,359)	2.9900%	1	(4,035)	ACCUM.	(446,419)	2.3600%	1	(9,786)
1987	(11,032)	3.0500%	0.5	(168)	1987	(19,590)	3.6400%	0.5	(357)
ACCUM.	(156,391)	3.0500%	1	(4,433)	ACCUM.	(466,009)	3.6400%	1	(16,250)
1988	(11,259)	3.0600%	0.5	(172)	1988	(78,956)	3.6400%	0.5	(1,437)
ACCUM.	(167,650)	3.0600%	1	(4,786)	ACCUM.	(544,965)	3.6400%	1	(16,963)
1989	(2,323)	3.0800%	0.5	(36)	1989	(12,285)	3.6400%	0.5	(224)
ACCUM.	(169,973)	3.0800%	1	(5,164)	ACCUM.	(557,250)	3.6400%	1	(19,837)
1990	(6,218)	3.0900%	0.5	(96)	1990	(17,022)	3.6400%	0.5	(310)
ACCUM.	(176,191)	3.0900%	1	(5,252)	ACCUM.	(574,272)	3.6400%	1	(20,284)
1991	(12,068)	3.0900%	0.5	(186)	1991	(36,375)	3.2300%	0.5	(587)
ACCUM.	(188,259)	3.0900%	1	(5,444)	ACCUM.	(610,647)	3.6400%	1	(20,904)
1992	(4,538)	3.0900%	0.5	(70)	1992	(6,844)	3.2300%	0.5	(111)
ACCUM.	(192,797)	3.0900%	1	(5,817)	ACCUM.	(617,491)	3.2300%	1	(19,724)
1993	(35,031)	3.1600%	0.5	(553)	1993	(120,759)	3.2300%	0.5	(1,950)
ACCUM.	(227,828)	3.1600%	1	(6,092)	ACCUM.	(738,250)	3.2300%	1	(19,945)
1994	(82,332)	3.0700%	0.5	(1,264)	1994	(191,314)	3.1700%	0.5	(3,032)
ACCUM.	(310,160)	3.0700%	1	(6,994)	ACCUM.	(929,564)	3.1700%	1	(23,403)
1995	(41,495)	3.0600%	0.5	(635)	1995	(231,650)	3.1700%	0.5	(3,672)
ACCUM.	(351,655)	3.0600%	1	(9,491)	ACCUM.	(1,161,214)	3.1700%	1	(29,467)

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1996	(15,535)	3.3900%	0.5	(263)	1996	(13,837)	3.1700%	0.5	(219)
ACCUM.	(367,190)	3.3900%	1	(11,921)	ACCUM.	(1,175,051)	3.1700%	1	(36,810)
1997	(17,395)	3.5100%	0.5	(305)	1997	(56,057)	3.1600%	0.5	(886)
ACCUM.	(384,585)	3.5100%	1	(12,888)	ACCUM.	(1,231,108)	3.1600%	1	(38,903)
1998	(23,485)	3.5100%	0.5	(412)	1998	(82,594)	3.1600%	0.5	(1,305)
ACCUM.	(408,070)	3.5100%	1	(13,499)	ACCUM.	(1,313,702)	3.1600%	1	(38,903)
1999	(859)	3.5100%	0.5	(15)	1999	(3,020)	3.1600%	0.5	(48)
ACCUM.	(408,929)	3.5100%	1	(14,323)	ACCUM.	(1,316,722)	3.1600%	1	(41,513)
2000	(5,759)	3.5100%	0.5	(101)	2000	(39,169)	3.1600%	0.5	(619)
ACCUM.	(414,688)	3.5100%	1	(14,353)	ACCUM.	(1,355,891)	3.1600%	1	(41,608)
2001	(8,721)	3.5100%	0.5	(153)	2001	(59,838)	3.1600%	0.5	(945)
ACCUM.	(423,409)	3.5100%	1	(14,556)	ACCUM.	(1,415,729)	3.1600%	1	(42,846)
2002	306	3.5100%	0.5	5	2002	1,436	3.1600%	0.5	23
ACCUM.	(423,103)	3.5100%	1	(14,862)	ACCUM.	(1,414,293)	3.1600%	1	(44,737)
2003	(18,503)	3.5100%	0.5	(325)	2003	(162,345)	3.1600%	0.5	(2,565)
ACCUM.	(441,606)	3.5100%	1	(14,851)	ACCUM.	(1,576,638)	3.1600%	1	(44,692)
2004	(8,249)	3.5100%	0.5	(145)	2004	(128,037)	3.1600%	0.5	(2,023)
ACCUM.	(449,855)	3.5100%	1	(15,500)	ACCUM.	(1,704,675)	3.1600%	1	(49,822)
2005	(24,177)	3.5100%	0.5	(424)	2005	(399,990)	3.1600%	0.5	(6,320)
ACCUM.	(474,032)	3.5100%	1	(15,790)	ACCUM.	(2,104,665)	3.1600%	1	(53,868)
2006	(8,849)	3.5100%	0.5	(155)	2006	(183,120)	3.1600%	0.5	(2,893)
ACCUM.	(482,881)	3.5100%	1	(16,639)	ACCUM.	(2,287,785)	3.1600%	1	(66,507)
2007	(150,665)	3.5100%	0.5	(2,644)	2007	(1,375,441)	3.1600%	0.5	(21,732)
ACCUM.	(633,546)	3.5100%	1	(16,949)	ACCUM.	(3,663,226)	3.1600%	1	(72,294)
2008	(10,497)	3.5100%	0.5	(184)	2008	(73,213)	3.1600%	0.5	(1,157)
ACCUM.	(644,043)	3.5100%	1	(22,237)	ACCUM.	(3,736,439)	3.1600%	1	(115,758)
2009	(159)	3.5993%	0.5	(3)	2009	(47,534)	2.9935%	0.5	(711)
ACCUM.	(644,202)	3.5993%	1	(23,181)	ACCUM.	(3,783,973)	2.9935%	1	(113,273)
2010	(960)	2.9874%	0.5	(14)	2010	(11,019)	2.1781%	0.5	(120)
ACCUM.	(645,162)	2.9874%	1	(19,245)	ACCUM.	(3,794,992)	2.1781%	1	(82,659)
2011	(775)	3.1391%	0.5	(12)	2011	(5,096)	2.3193%	0.5	(59)
ACCUM.	(645,937)	3.1391%	1	(20,252)	ACCUM.	(3,800,088)	2.3193%	1	(88,135)
2012	(646)	3.1330%	0.5	(10)	2012	(11,116)	2.3059%	0.5	(128)
ACCUM.	(646,583)	3.1330%	1	(20,237)	ACCUM.	(3,811,203)	2.3059%	1	(87,883)
2013	582	3.1606%	0.5	9	2013	12,925	2.2926%	0.5	148
ACCUM.	(646,001)	3.1606%	1	(20,436)	ACCUM.	(3,798,278)	2.2926%	1	(87,079)
2014	1,175	3.0920%	0.5	18	2014	25,844	2.3224%	0.5	300
ACCUM.	(644,826)	3.0920%	1	(19,975)	ACCUM.	(3,772,435)	2.3224%	1	(87,612)
2015	1,734	3.0964%	0.5	27	2015	5,129	2.3034%	0.5	59
ACCUM.	(643,091)	3.0964%	1	(19,966)	ACCUM.	(3,767,306)	2.3034%	1	(86,778)
2016	3,646	3.0922%	0.5	56	2016	6,618	2.3117%	0.5	76

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ACCUM.	(639,445)	3.0922%	1	(19,886)	ACCUM.	(3,760,688)	2.3117%	1	(86,937)
2017	1,708	3.0452%	0.5	26	2017	18,576	2.2813%	0.5	212
ACCUM.	(637,737)	3.0452%	1	(19,473)	ACCUM.	(3,742,111)	2.2813%	1	(85,370)
201806	1,382	3.0452%	0.5	21	201806	14,662	2.2813%	0.5	167
ACCUM.	(636,355)	3.0452%	1	(19,421)	ACCUM.	(3,727,449)	2.2813%	1	(85,035)
Ending balance	(636,355)			(473,709)		(3,727,449)			(1,848,263)
Total									(6,601,615)

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	PRODUCTION	TRANS.	DISTR.	GENERAL	TOTAL
6/30/2018	(3,344,109)	(935,534)	(1,848,263)	(473,709)	(6,601,615)
July 2018 Balanc	(3,348,376)	(939,095)	(1,855,335)	(475,326)	(6,618,132)
Aug-Dec 2018	(21,333)	(17,807)	(35,362)	(8,083)	(82,585)
12/31/2018	(3,369,709)	(956,902)	(1,890,697)	(483,409)	(6,700,717)
Jan - Dec 2019	(51,200)	(42,736)	(84,868)	(19,400)	(198,204)
12/31/2019	(3,420,909)	(999,638)	(1,975,565)	(502,809)	(6,898,921)

Purpose: To adjust pro-forma year accumulated depreciation for jurisdictional equity AFUDC differences
See electronic file provided: Equity AFUDC ADJ Arkansas-Jun-18.xls.
Supporting Schedules:

Recap Schedules:
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Pro Forma Adjustment Gross Plant
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Line No.	Account	Plant	Per Books 7/31/2018(a)	TY 2018 Additions	Projected TY 2018 Retirements	Test Year	Pro Forma 2019 Additions	Pro Forma for 2019 Retirements	Pro Forma Year
		INTANGIBLE PLANT							
1	301	Organization	12,202	-	-	12,202	-	-	12,202
2	302	Franchise and Consents	-			-			-
3	303	Miscellaneous Intangible Plant	97,658,520	32,663,367.00	(8,098,000.00)	122,223,887	39,885,556	(12,159,000)	149,950,443
4		TOTAL INTANGIBLE PLANT	$ 97,670,722	$ 32,663,367	$ (8,098,000)	$ 122,236,089	$ 39,885,556	$ (12,159,000)	$ 149,962,645
5		PRODUCTION PLANT							
6		STEAM PRODUCTION							
7	310	Land and Land Rights	26,969,480	-		26,969,480			26,969,480
8	311	Structures and Improvement	629,284,547	7,125,900	(2,243,870)	634,166,577	7,635,064	(3,778,891)	638,022,750
9	312	Boiler Plant Equipment	2,663,794,579	38,364,375	(12,080,511)	2,690,078,443	41,176,336	(20,344,765)	2,710,910,014
10	314	Turbogenerator Units	727,750,627	5,725,064	(1,802,761)	731,672,930	6,178,223	(3,036,023)	734,815,130
11	315	Accessory Electric Equipment	237,973,895	3,292,543	(1,036,791)	240,229,647	3,527,804	(1,746,048)	242,011,403
12	316	Miscellaneous Power Plant Equipment	214,848,118	2,941,869	(926,363)	216,863,624	3,152,073	(1,560,084)	218,455,613
13	317	ARO Steam Production Plant	58,944,290	-		58,944,290			58,944,290
14		TOTAL STEAM PRODUCTION	$ 4,559,565,536	$ 57,449,751	$ (18,090,296)	$ 4,598,924,991	$ 61,669,500	$ (30,465,811)	$ 4,630,128,680
15		OTHER PRODUCTION							
16	340	Land and Land Rights	1,451,852	-	-	1,451,852	-	-	1,451,852
17	341	Structures and Improvement	34,912,751	445,729	(140,354)	35,218,126	477,579	(236,373)	35,459,332
18	342	Fuel Holders, Products, and Accessories	-	-		-			-
19	343	Prime movers	-	-		-			-
20	344	Generators	84,008,692	1,072,538	(337,730)	84,743,500	1,149,172	(568,770)	85,323,902
21	345	Accessory Electric Equipment	8,994,738	114,835	(36,159)	9,073,414	123,041	(60,898)	9,135,557
22	346	Miscellaneous Power Plant Equipment	784,464	10,015	(3,155)	791,324	10,731	(5,311)	796,744
23	347	ARO Cost for Other Production	-	-	-	-	-	-	-
24		TOTAL OTHER PRODUCTION	$ 130,152,498	$ 1,643,117	$ (517,398)	$ 131,278,217	$ 1,760,523	$ (871,352)	$ 132,167,388
25		TOTAL PRODUCTION PLANT	$ 4,689,718,034	$ 59,092,868	$ (18,607,694)	$ 4,730,203,208	$ 63,430,023	$ (31,337,163)	4,762,296,068
									-
26		TRANSMISSION PLANT							-
27	350	Land and Land Rights	97,320,963	2,326,710	(94,480)	99,553,193	8,703,878	(292,645)	107,964,426
28	352	Structures and Improvements	14,717,825	370,024	(15,025)	15,072,824	1,384,202	(46,540)	16,410,486
29	353	Station Equipment	619,251,082	15,568,687	(632,201)	634,187,568	58,240,153	(1,958,172)	690,469,549
30	354	Towers and Fixtures	40,872,806	1,027,591	(41,730)	41,858,667	3,844,060	(129,246)	45,573,481
31	355	Poles and Fixtures	647,359,524	16,275,366	(660,900)	662,973,990	60,883,732	(2,047,055)	721,810,667
32	356	Overhead Conductors and Devices	380,513,258	9,566,544	(388,470)	389,691,332	35,787,018	(1,203,244)	424,275,106
33	357	Underground Conduit	2,069,255	52,022	(2,115)	2,119,162	194,612	(6,543)	2,307,231
34	358	Underground Conductors and Devices	40,340	1,007	(40)	41,307	3,766	(127)	44,946
35	359	Roads and Trails	131,947			131,947			131,947
36		TOTAL TRANSMISSION PLANT	$ 1,802,277,001	$ 45,187,951	$ (1,834,961)	$ 1,845,629,991	$ 169,041,421	$ (5,683,572)	$ 2,008,987,840

Southwestern Electric Power Company
Pro Forma Adjustment Gross Plant
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP B 2-4

Line No.	Account	Plant	Per Books 7/31/2018(a)	TY 2018 Additions	Projected TY 2018 Retirements	Test Year	Pro Forma 2019 Additions	Pro Forma for 2019 Retirements	Pro Forma Year
37		DISTRIBUTION PLANT							
38	360	Land and Land Rights	11,419,206	-	-	11,419,206	-	-	11,419,206
39	361	Structures and Improvements	7,775,648	252,037	(34,750)	7,992,935	514,444	(86,904)	8,420,475
40	362	Station Equipment	307,422,114	9,964,645	(1,373,965)	316,012,794	20,339,310	(3,435,899)	332,916,205
41	364	Poles, Towers, and Fixtures	438,848,632	14,224,642	(1,961,355)	451,111,919	29,034,603	(4,904,785)	475,241,737
42	365	Overhead Conductors and Devices	439,915,586	14,259,229	(1,966,125)	452,208,690	29,105,193	(4,916,708)	476,397,175
43	366	Underground Conduit	66,522,478	2,156,230	(297,310)	68,381,398	4,401,184	(743,487)	72,039,095
44	367	Underground Conductors and Devices	219,395,395	7,111,385	(980,550)	225,526,230	14,515,387	(2,452,069)	237,589,548
45	368	Line Transformers	386,576,527	12,530,321	(1,727,735)	397,379,113	25,576,234	(4,320,567)	418,634,780
46	369	Services	90,906,356	2,946,599	(406,290)	93,446,665	6,014,442	(1,016,013)	98,445,094
47	370	Meters	84,378,024	2,734,991	(377,115)	86,735,900	5,582,522	(943,050)	91,375,372
48	371	Installations on Customers' Premises	43,598,031	1,413,168	(194,855)	44,816,344	2,884,483	(487,273)	47,213,554
49	373	Street Lighting and Signal Systems	41,871,653	1,357,210	$ (187,140)	43,041,723	2,770,264	(467,978)	45,344,009
50		TOTAL DISTRIBUTION PLANT	$ 2,138,629,650	$ 68,950,457	$ (9,507,190)	$ 2,198,072,917	$ 140,738,066	$ (23,774,733)	$ 2,315,036,250
51		GENERAL PLANT							
52	389	Land and Land Rights	18,643,207	-		18,643,207	-		18,643,207
53	390	Structures and Improvements	104,459,189	1,210,106	(777,556)	104,891,739	1,535,993	(2,138,192)	104,289,540
54	391	Office Furniture and Equipment	10,059,127	801	(515)	10,059,413	1,017	(1,416)	10,059,014
55	392	Transportation Equipment	4,118,518	-	-	4,118,518	-	-	4,118,518
56	393	Stores Equipment	2,994,676	34,692	(22,290)	3,007,078	44,034	(61,298)	2,989,814
57	394	Tools, Shop and Garage Equipment	26,341,827	305,157	(196,080)	26,450,904	387,337	(539,195)	26,299,046
58	395	Laboratory Equipment	5,501,275	-	-	5,501,275	-	-	5,501,275
59	396	Power Operated Equipment	759,763	-	-	759,763	-	-	759,763
60	397	Communication Equipment	36,404,311	416,288	(267,485)	36,553,114	528,399	(735,561)	36,345,952
61	398	Miscellaneous Equipment	2,596,116	30,076	(19,325)	2,606,867	38,174	(53,140)	2,591,901
62	399	Other Tangible Property	89,356,447	773,030	(496,715)	89,632,762	981,212	(1,365,903)	89,248,071
63		TOTAL GENERAL PLANT	$ 301,234,453	$ 2,770,150	$ (1,779,966)	$ 302,224,637	$ 3,516,166	$ (4,894,705)	$ 300,846,098
64		TOTAL COMPANY PLANT IN SERVICE	$ 9,029,529,860	$ 208,664,793 (B)	$ (30,507,761)	$ 9,198,366,842 (A)	$ 416,611,232 (A)	$ (77,849,173)	$ 9,537,128,901

PURPOSE:
Rollforward of gross utility plant from the historical test year end to the pro-forma year end.

Supporting Schedules and Workpapers:
(a) E-17 Part II A

Recap Schedules:
(A) Schedule B-2

Southwestern Electric Power Company **WP B 2-5**
Turk Adjustments - Summary
Test Year Ending December 31, 2018
Docket No. 19-008-U

SWEPCo Turk Plant

			12/31/2018	12/31/2019	
Plant In Service (a)			1,683,982,430	1,695,333,495	(A)
Accumulated Reserve (a)			(198,321,687)	(209,400,477)	
			1,485,660,743	1,485,933,018	(B)
Turk Inventory (b)			9,586,328	9,586,328	
Turk Prepaid Pension (b)			7,590,434	7,590,434	
SFAS 109 Regulatory Asset-AFUDC Eq G.U. (c)			39,209,439	38,292,893	(C)
SFAS 109 ADIT - X-ADIT G.U. (c)			43,219,711	42,511,572	(D)
Plant Held for Future Use (d)			204,896	204,896	
Other Assets (e)			7,120,272	7,120,272	
Total Assets			1,549,372,111	1,548,727,840	
Capital					
ADIT (c)			245,585,392	242,537,841	(E)
Reg Liab - X-ADIT (c)			162,588,436	159,924,484	(D)
Reg Liab - X-ADIT - G.U. (c)			43,219,711	42,511,572	(D)
SFAS 109 ADIT on AFUDC Eq with G.U.			39,209,439	38,292,893	(C)
LTD	65%	65%	684,415,254	688,741,079	(F)
Equity	35%	35%	374,353,880	376,719,972	(F)
Total Liabilities & Equity			1,549,372,111	1,548,727,840	

	7/31/2018	7/31/2018
Debt(f)	4,163,619,417	4,163,619,417
Equity(f)	2,277,370,461	2,277,370,461
	6,440,989,878	6,440,989,878
	1,058,769,134	1,065,461,050

Purpose: Summarize the elimination of Turk from rate base and supporting associated cost of capital balances.

Supporting Schedules and Workpapers:		Recap
(a) WP 2-5-1	(A)	B-2
(b) WP B 4-3	(B)	WP 2-17-1, WP B 2-5-1
(c) WP 2-5-2	(C)	B-4, WP C 10-5
(d) B-7	(D)	WP C 10-4, D-6.1
(e)WP B 4-1	(E)	D-1.2, D-1.3, WP C 10-5
(f) D-1.2	(F)	D-2.2, D-2.3, WP D 1-4

Southwestern Electric Power Company **WP B 2-5-1**
Turk Net Plant Values
Test Year Ending December 31, 2018
Docket No. 19-008-U

Generating Power Station

Gross Plant

	Historic Balances			Forecasted Balances			
Account	7/31/18	8/31/18	9/30/2018	10/31/18	11/30/18	12/31/18	12/31/19
Turk(a)							
31000 - Land - Coal Fired	11,468,899	11,468,899	11,468,899	11,468,899	11,468,899	11,468,899	11,468,899
31010 - Land Rights - Coal Fire	1,886,717	1,886,717	1,886,717	1,886,717	1,886,717	1,886,717	1,886,717
31100 - Structures, Improvemn	285,601,333	285,250,189	286,108,949	287,123,161	288,146,372	288,505,241	290,798,952
31200 - Boiler Plant Equip-Coa	986,401,348	985,188,575	988,154,535	991,657,391	995,191,326	996,430,785	1,004,352,733
31400 - Turbogenerator Units-(	232,599,492	232,599,492	232,599,492	232,599,492	232,599,492	232,599,492	232,599,492
31500 - Accessory Elect Equip-	93,356,005	93,241,225	93,521,932	93,853,453	94,187,916	94,305,219	95,054,977
31600 - Misc Pwr Plant Equip-(	48,018,866	47,959,827	48,104,213	48,274,735	48,446,770	48,507,106	48,892,754
31700 - ARO Steam Productior	2,179,313	2,179,313	2,179,313	2,179,313	2,179,313	2,179,313	2,179,313
Total	**1,661,511,973**	**1,659,774,237**	**1,664,024,050**	**1,669,043,161**	**1,674,106,805**	**1,675,882,772**	**1,687,233,837**

Accumulated Depreciation

	Historic Balances			Forecasted Balances			
Account	7/31/18	8/31/18	9/30/2018	10/31/18	11/30/18	12/31/18	12/31/19
31000 - Land - Coal Fired							
31010 - Land Rights - Coal Fired							
31100 - Structures, Improvemn	32,397,430	32,469,220	32,625,037	32,782,496	32,945,414	32,987,306	34,816,214
31200 - Boiler Plant Equip-Coa	116,256,879	116,514,494	117,073,638	117,638,672	118,223,298	118,373,625	124,936,588
31400 - Turbogenerator Units-(	28,998,108	29,062,365	29,201,833	29,342,770	29,488,594	29,526,091	31,163,099
31500 - Accessory Elect Equip-	11,014,050	11,038,456	11,091,429	11,144,959	11,200,346	11,214,588	11,836,356
31600 - Misc Pwr Plant Equip-(	4,925,868	4,936,783	4,960,474	4,984,415	5,009,186	5,015,555	5,293,632
31700 - ARO Steam Productior	290,906	291,551	292,950	294,364	295,827	296,203	312,625
Total	**193,883,240**	**194,312,869**	**195,245,361**	**196,187,676**	**197,162,665**	**197,413,368**	**208,358,514**

NBV

	Historic Balances			Forecasted Balances			
Account	7/31/18	8/31/18	9/30/2018	10/31/18	11/30/18	12/31/18	12/31/19
31000 - Land - Coal Fired	11,468,899	11,468,899	11,468,899	11,468,899	11,468,899	11,468,899	11,468,899
31010 - Land Rights - Coal Fire	1,886,717	1,886,717	1,886,717	1,886,717	1,886,717	1,886,717	1,886,717
31100 - Structures, Improvemn	253,203,903	252,780,969	253,483,912	254,340,665	255,200,958	255,517,935	255,982,738
31200 - Boiler Plant Equip-Coa	870,144,469	868,674,081	871,080,897	874,018,719	876,968,028	878,057,160	879,416,145
31400 - Turbogenerator Units-(	203,601,384	203,537,127	203,397,659	203,256,722	203,110,898	203,073,401	201,436,393
31500 - Accessory Elect Equip-	82,341,956	82,202,769	82,430,503	82,708,494	82,987,570	83,090,631	83,218,621
31600 - Misc Pwr Plant Equip-(	43,092,998	43,023,044	43,143,739	43,290,320	43,437,584	43,491,551	43,599,122
31700 - ARO Steam Productior	1,888,406	1,887,762	1,886,363	1,884,949	1,883,486	1,883,110	1,866,688
Total	**1,467,628,733**	**1,465,461,368**	**1,468,778,689**	**1,472,855,485**	**1,476,944,140**	**1,478,469,404**	**1,478,875,323**

Southwestern Electric Power Company **WP B 2-5-1**
Turk Net Plant Values
Test Year Ending December 31, 2018
Docket No. 19-008-U
Generator Step-up Units(1)

Gross Plant	Historic Balances			Forecasted Balances			
Account	7/31/18	8/31/18	9/30/2018	10/31/18	11/30/18	12/31/18	12/31/19
Turk							
35300 - Station Equipment	8,099,658	8,099,658	8,099,658	8,099,658	8,099,658	8,099,658	8,099,658
Total	**8,099,658**	**8,099,658**	**8,099,658**	**8,099,658**	**8,099,658**	**8,099,658**	**8,099,658**
Accumulated Depreciation							
	Historic Balances			Forecasted Balances			
Account	7/31/18	8/31/18	9/30/2018	10/31/18	11/30/18	12/31/18	12/31/19
35300 - Station Equipment	852,634	863,771	874,908	886,045	897,182	908,319	1,041,963
Total	**852,634**	**863,771**	**874,908**	**886,045**	**897,182**	**908,319**	**1,041,963**
NBV							
	Historic Balances			Forecasted Balances			
Account	7/31/18	8/31/18	9/30/2018	10/31/18	11/30/18	12/31/18	12/31/19
35300 - Station Equipment	7,247,024	7,235,887	7,224,750	7,213,613	7,202,476	7,191,339	7,057,695
Total		**7,235,887**	**7,224,750**	**7,213,613**	**7,202,476**	**7,191,339**	**7,057,695**

Purpose: Summarize Turk net plant balances.

Supporting Schedules and Workpapers:
(a) E 17 Part II A

Recap
WP B 2-5

Southwestern Electric Power Company **WP B 2-5-2**
Adjustment to Remove Turk ADIT and Related FAS 109 Balances
Test Year Ending December 31, 2018
Docket No. 19-008-U

Tax GU for 21% Tax Rate	1.266
FIT Rate	0.21

2018

		Turk Amounts Debit (Credit)			Increase (Decrease) (A)		
		ADIT	ADIT Portion at 21%	Excess ADIT Reg Liability	Adjust ADIT	Adjust SFAS 109 Reg Liab	Adjust SFAS 109 Reg Asset
Beg Year ADFIT	(a)	(413,192,181)	(250,603,745)	(162,588,436)			
2018 Activity	(a)	5,018,353	5,018,353	0			
Total		(408,173,828)	(245,585,392)	(162,588,436)	(245,585,392)	(162,588,436)	
SFAS 109 Reg Liability			Liability Acct 254	(162,588,436)			
SFAS 109 GU of Reg Liability			Liability Acct 254	(43,219,711)		(43,219,711)	
SFAS 109 ADIT on Reg Liability Gross-up			Asset Acct 190	43,219,711	(43,219,711)		
Unamortized AFUDC-Eq	(a)			147,502,175			
SFAS 109 Reg Asset				39,209,439			(39,209,439)
SFAS 109 ADIT on AFUDC Gross up				(39,209,439)	(39,209,439)		

2019

		Turk Amounts Debit (Credit)			**Increase (Decrease)(A)**		
		ADIT	Portion at 21%	Excess ADIT Reg Liability	Adjust ADIT	Adjust SFAS 109 Reg Liab	Adjust SFAS 109 Reg Asset
Beg Year ADFIT	(a)	(408,173,828)	(248,249,344)	(159,924,484)			
2018 Activity	(a)	5,711,502	5,711,502	0			
Total		(402,462,325)	(242,537,841)	(159,924,484)	(242,537,841)	(159,924,484)	
SFAS 109 Reg Liability			254.00	(159,924,484)			
SFAS 109 GU of Reg Liability			254.00	(42,511,572)		(42,511,572)	
SFAS 109 ADIT on Reg Liability Gross-up			190.00	42,511,572	(42,511,572)		
Unamortized AFUDC-Eq				144,054,215			
SFAS 109 Reg Asset			182.30	38,292,893			(38,292,893)
SFAS 109 ADIT on AFUDC Gross up			282-283	(38,292,893)	(38,292,893)		

Purpose: To quantify Turk ADIT and related regulatory assets and liabilities for elimination

The ADIT balances are from the Company's tax system of which Turk is a separately identified tax class.

Supporting Schedules and Workpapers:
(a) WP B 2-5-3

Recap
(A) WP 2-5, B-4, WP C 10-5,WP C 10-4, D-6.1

Southwestern Electric Power Company
Turk ADIT Tax Reports
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP B 2-5-3

Source: 2018 Power Tax Report- Turk ADIT

Jurisdiction: Federal AEP West	" Beginning Difference"	" Current Difference"	" Ending Difference"	"Beginning APB11 DFIT Balance"	" Current DFIT"	"Ending APB11 DFIT Balance"	"End FAS109 Liability @ Stat Rate"	"Regulatory Asset Before Gross-Up"	"Regulatory Liab Before Gross-Up"	"Regulatory Asset After Gross-Up"	"Regulatory Liab After Gross-Up"
Tax Year: 2018											
PowerTax Deferred Tax Summary Report											
0001 SWEPCO Turk 18 & 19 EST											
Southwestern Electric Pwr - Gen											
Grouped By: Total Tax Classes											
SEP-G FED Method/Life	$1,221,382,016	($12,213,524)	$1,209,168,492	$427,483,706	($5,409,892)	$422,073,814	$253,925,383	$0	($168,148,430)	$0	($212,846,114)
Depreciation Difference	**$1,221,382,016**	**($12,213,524)**	**$1,209,168,492**	**$427,483,706**	**($5,409,892)**	**$422,073,814**	**$253,925,383**	**$0**	**($168,148,430)**	**$0**	**($212,846,114)**
SEP-G FED AFUDC Debt	$132,486,603	($3,340,054)	$129,146,549	$46,370,311	($1,169,019)	$45,201,292	$27,120,775	$0	($18,080,517)	$0	($22,886,730)
SEP-G FED Bk/Tx Unit of Property	$3,249,251	($60,919)	$3,188,332	$1,137,238	($21,322)	$1,115,916	$669,550	$0	($446,366)	$0	($565,021)
SEP-G FED Capitalized Interest	($203,156,855)	$5,120,592	($198,036,263)	($71,104,899)	$1,792,207	($69,312,692)	($41,587,615)	$0	$27,725,077	$0	$35,095,034
SEP-G FED Contra CPI	($160,477)	$3,075	($157,402)	($56,167)	$1,076	($55,091)	($33,055)	$0	$22,036	$0	$27,894
SEP-G FED Overheads	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SEP-G FED R&D Basis Adjustment	$26,748,551	($604,011)	$26,144,540	$9,361,993	($211,404)	$9,150,589	$5,490,353	$0	($3,660,236)	$0	($4,633,210)
Book Overhead	**($40,832,928)**	**$1,118,683**	**($39,714,245)**	**($14,291,525)**	**$391,539**	**($13,899,986)**	**($8,339,991)**	**$0**	**$5,559,994**	**$0**	**$7,037,967**
SEP-G FED AFUDC Equity	$151,323,770	($3,821,595)	$147,502,175	$0	$0	$0	$30,975,457	$30,975,457	$0	$39,209,439	$0
SEP-G FED CPI FT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Book Overhead	**$151,323,770**	**($3,821,595)**	**$147,502,175**	**$0**	**$0**	**$0**	**$30,975,457**	**$30,975,457**	**$0**	**$39,209,439**	**$0**
Total Tax Classes	$1,331,872,858	($14,916,437)	$1,316,956,421	$413,192,181	($5,018,353)	$408,173,828	$276,560,848	$30,975,457	($162,588,436)	$39,209,439	($205,808,147)
Jurisdiction Totals:	**$1,331,872,858**	**($14,916,437)**	**$1,316,956,421**	**$413,192,181**	**($5,018,353)**	**$408,173,828**	**$276,560,848**	**$30,975,457**	**($162,588,436)**	**$39,209,439**	**($205,808,147)**
Company Totals:	**$1,331,872,858**	**($14,916,437)**	**$1,316,956,421**	**$413,192,181**	**($5,018,353)**	**$408,173,828**	**$276,560,848**	**$30,975,457**	**($162,588,436)**	**$39,209,439**	**($205,808,147)**
PwrTax - 257	02/22/2019 at 1:14 pm										

Southwestern Electric Power Company **WP B 2-5-3**
Turk ADIT Tax Reports
Test Year Ending December 31, 2018
Docket No. 19-008-U
Source: 2019 Power Tax Report- Turk ADIT

Jurisdiction: Federal AEP West	" Beginning Difference"	" Current Difference"	" Ending Difference"	"Beginning APB11 DFIT Balance"	" Current DFIT"	"Ending APB11 DFIT Balance"	"End FAS109 Liability @ Stat Rate"	"Regulatory Asset Before Gross-Up"	"Regulatory Liab Before Gross-Up"	"Regulatory Asset After Gross-Up"	"Regulatory Liab After Gross-Up"
Tax Year: 2019											
PowerTax Deferred Tax Summary Report											
0001 SWEPCO Turk 18 & 19 EST											
Southwestern Electric Pwr - Gen											
Grouped By: Total Tax Classes											
SEP-G FED Method/Life	$1,209,168,492	($15,937,294)	$1,193,231,198	$422,073,814	($6,210,305)	$415,863,509	$250,578,552	$0	($165,284,957)	$0	($209,221,465)
Depreciation Difference	**$1,209,168,492**	**($15,937,294)**	**$1,193,231,198**	**$422,073,814**	**($6,210,305)**	**$415,863,509**	**$250,578,552**	**$0**	**($165,284,957)**	**$0**	**($209,221,465)**
SEP-G FED AFUDC Debt	$129,146,549	($3,016,164)	$126,130,385	$45,201,292	($1,055,657)	$44,145,635	$26,487,381	$0	($17,658,254)	$0	($22,352,220)
SEP-G FED Bk/Tx Unit of Property	$3,188,332	($61,616)	$3,126,716	$1,115,916	($21,566)	$1,094,351	$656,610	$0	($437,740)	$0	($554,102)
SEP-G FED Capitalized Interest	($198,036,263)	$5,264,177	($192,772,086)	($69,312,692)	$1,842,462	($67,470,230)	($40,482,138)	$0	$26,988,092	$0	$34,162,142
SEP-G FED Contra CPI	($157,402)	$3,110	($154,292)	($55,091)	$1,089	($54,002)	($32,401)	$0	$21,601	$0	$27,343
SEP-G FED Overheads	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SEP-G FED R&D Basis Adjustment	$26,144,540	($764,358)	$25,380,181	$9,150,589	($267,525)	$8,883,064	$5,329,838	$0	($3,553,225)	$0	($4,497,754)
Book Overhead	($39,714,245)	$1,425,150	($38,289,096)	($13,899,986)	$498,802	($13,401,183)	($8,040,710)	$0	$5,360,473	$0	$6,785,409
SEP-G FED AFUDC Equity	$147,502,175	($3,447,960)	$144,054,215	$0	$0	$0	$30,251,385	$30,251,385	$0	$38,292,893	$0
SEP-G FED CPI FT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Book Overhead	**$147,502,175**	**($3,447,960)**	**$144,054,215**	**$0**	**$0**	**$0**	**$30,251,385**	**$30,251,385**	**$0**	**$38,292,893**	**$0**
Total Tax Classes	$1,316,956,421	($17,960,104)	$1,298,996,317	$408,173,828	($5,711,502)	$402,462,325	$272,789,227	$30,251,385	($159,924,484)	$38,292,893	($202,436,056)
Jurisdiction Totals:	**$1,316,956,421**	**($17,960,104)**	**$1,298,996,317**	**$408,173,828**	**($5,711,502)**	**$402,462,325**	**$272,789,227**	**$30,251,385**	**($159,924,484)**	**$38,292,893**	**($202,436,056)**
Company Totals:	**$1,316,956,421**	**($17,960,104)**	**$1,298,996,317**	**$408,173,828**	**($5,711,502)**	**$402,462,325**	**$272,789,227**	**$30,251,385**	**($159,924,484)**	**$38,292,893**	**($202,436,056)**
PwrTax - 257	02/22/2019 at 1:17 pm										

Purpose: Provide Tax ADIT balances from Tax system.

Supporting Schedules and Workpapers:

Recap
(A) WP B 2-5-2

Southwestern Electric Power Company
Pro-forma Amounts for Adjusting Accumulated Depreciation
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP B 2-6

Line No.	Account	Plant	12/31/2018 Test Year Accumulated Depr (a)	Pro Forma 2019 Projected Depr Exp	Pro Forma 2019 Projected Retirements	Pro Forma 2019 Projected Removal Exp	Pro Forma 12/31/2019 Accumulated Depr
		INTANGIBLE PLANT					
1	301	Organization	-	-	-	-	-
2	302	Franchise and Consents	-	-	-	-	-
3	303	Miscellaneous Intangible Plant	50,972,631	18,937,197	(16,103,462)	-	53,806,366
4		TOTAL INTANGIBLE PLANT	$ 50,972,631	$ 18,937,197	$ (16,103,462)	$ -	**$ 53,806,366**
5		PRODUCTION PLANT					
6		STEAM PRODUCTION					
7	310	Land and Land Rights	9,535	-	-	-	9,535
8	311	Structures and Improvements	274,710,600	24,487,810	(7,228,122)	(1,721,279)	290,249,008
9	312	Boiler Plant Equipment	804,086,550	73,195,159	(21,605,183)	(5,144,980)	850,531,546
10	314	Turbogenerator Units	240,642,486	21,573,179	(6,367,805)	(1,516,406)	254,331,454
11	315	Accessory Electric Equipment	73,275,282	6,661,457	(1,966,275)	(468,242)	77,502,222
12	316	Miscellaneous Power Plant Equipment	80,625,694	7,092,810	(2,093,602)	(498,562)	85,126,339
13	317	ARO Cost for Steam Production	10,553,705	922,170	(272,199)	(64,823)	11,138,853
14		TOTAL STEAM PRODUCTION	$ 1,483,903,851	$133,932,585	$ (39,533,187)	$ (9,414,292)	**$ 1,568,888,958**
15		OTHER PRODUCTION					
16	340	Land and Land Rights	-	-	-	-	-
17	341	Structures and Improvements	8,976,828	784,387	(231,529)	(55,136)	9,474,550
18	342	Fuel Holders. Products, and Accessories	-	-	-	-	-
19	343	Prime movers	-	-	-	-	-
20	344	Generators	22,373,637	1,954,988	(577,059)	(137,419)	23,614,148
21	345	Accessory Electric Equipment	1,540,726	134,627	(39,739)	(9,463)	1,626,152
22	346	Miscellaneous Power Plant Equipment	115,419	10,085	(2,977)	(709)	121,817
23	347	ARO Cost for Other Production	-	-	-	-	-
24		TOTAL OTHER PRODUCTION	$ 33,006,611	$ 2,884,087	$ (851,304)	$ (202,727)	**$ 34,836,667**
25		TOTAL PRODUCTION PLANT	$ 1,516,910,462	$136,816,672	$ (40,384,490)	$ (9,617,019)	**$ 1,603,725,624**
26		TRANSMISSION PLANT					
27	350	Land and Land Rights	27,750,850	2,414,460	(706,158)	(169,717)	29,289,435
28	352	Structures and Improvements	5,677,407	496,087	(146,431)	(34,870)	5,992,193
29	353	Station Equipment	174,592,108	15,255,702	(4,503,059)	(1,072,341)	184,272,409
30	354	Towers and Fixtures	28,341,074	2,476,417	(730,970)	(174,073)	29,912,448
31	355	Poles and Fixtures	164,642,617	14,386,319	(4,246,442)	(1,011,232)	173,771,262
32	356	Overhead Conductors and Devices	127,017,332	11,098,656	(3,276,016)	(780,139)	134,059,833
33	357	Underground Conduit	13,149	1,149	(339)	(80)	13,879
34	358	Underground Conductors and Devices	587	50	(15)	(3)	619
35	359	Roads and Trails	96,397	8,423	(2,487)	(592)	101,742
36		TOTAL TRANSMISSION PLANT	$ 528,131,521	$ 46,137,263	$ (13,611,917)	$ (3,243,047)	**$ 557,413,820**
37		DISTRIBUTION PLANT					

Southwestern Electric Power Company **WP B 2-6**
Pro-forma Amounts for Adjusting Accumulated Depreciation
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Account	Plant	12/31/2018 Test Year Accumulated Depr (a)	**Pro Forma** 2019 Projected Depr Exp	**Pro Forma** 2019 Projected Retirements	**Pro Forma** 2019 Projected Removal Exp	**Pro Forma** 12/31/2019 Accumulated Depr
38	360	Land and Land Rights	2,407,927	209,502	(61,273)	(14,727)	2,541,429
39	361	Structures and Improvements	2,400,959	209,794	(61,925)	(14,746)	2,534,082
40	362	Station Equipment	88,815,121	7,760,584	(2,290,708)	(545,502)	93,739,494
41	364	Poles, Towers, and Fixtures	195,262,268	17,061,841	(5,036,182)	(1,199,298)	206,088,629
42	365	Overhead Conductors and Devices	157,718,325	13,781,283	(4,067,853)	(968,704)	166,463,051
43	366	Underground Conduit	25,779,190	2,252,562	(664,894)	(158,336)	27,208,523
44	367	Underground Conductors and Devices	100,476,439	8,779,539	(2,591,477)	(617,125)	106,047,376
45	368	Line Transformers	121,428,624	10,610,321	(3,131,873)	(745,813)	128,161,259
46	369	Services	39,937,945	3,489,740	(1,030,075)	(245,298)	42,152,312
47	370	Meters	(40,823,256)	(3,567,098)	1,052,908	250,736	(43,086,710)
48	371	Installation on Customer Premises	25,618,404	2,238,513	(660,748)	(157,347)	27,038,822
49	373	Street Lighting and Signal Systems	26,093,546	2,280,031	(673,002)	(160,266)	27,540,309
50		TOTAL DISTRIBUTION PLANT	$ 745,115,493	$ 65,106,612	$(19,217,102)	$ (4,576,426)	**$ 786,428,577**
51		GENERAL PLANT					
52	389	Land and Land Rights	(196,427)	(17,090)	4,998	1,202	(207,317)
53	390	Structures and Improvements	43,634,396	3,812,732	(1,125,413)	(268,001)	46,053,714
54	391	Office Furniture and Equipment	6,591,599	366,823	(108,275)	(25,785)	6,824,362
55	392	Transportation Equipment	3,736,339	325,809	(96,171)	(22,901)	3,943,076
56	393	Stores Equipment	1,735,220	151,622	(44,755)	(10,656)	1,831,431
57	394	Tools, Shop and Garage Equipment	9,103,313	795,439	(234,792)	(55,913)	9,608,047
58	395	Laboratory Equipment	5,455,372	142,637	(42,101)	(10,026)	5,545,881
59	396	Power Operated Equipment	31,052	2,713	(800)	(191)	32,774
60	397	Communication Equipment	17,860,569	1,475,491	(435,525)	(103,714)	18,796,820
61	398	Miscellaneous Equipment	1,301,135	110,191	(32,526)	(7,744)	1,371,056
62	399	Other Tangible Property	76,120,668	6,342,692	(1,872,188)	(445,836)	80,145,336
63		TOTAL GENERAL PLANT	$ 165,373,236	$ 13,509,059	$ (3,987,548)	$ (949,565)	**$ 173,945,182**
64		TOTAL COMPANY Accumulated Depreciation	**$ 3,006,503,342**	**$280,506,803**	**$(93,304,519)**	**$(18,386,057)**	**$ 3,175,319,569**
			(a)	(A)	(A)	(A)	

Purpose: Quantify pro-forma year additions and retirements to accumulated depreciation.

Supporting Schedules and Workpapers:
(a) WP B 2-6-1

Recap Schedule:
(A) Schedule B-2

Southwestern Electric Power Company
Test Year Rollfoward of Accumulated Depreciation
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP B 2-6-1

Line No.	Account	Plant	7/31/2018 Test Year Accumulated Depr	Test Year 2018 Projected Depr Exp	Test Year 2018 Projected Retirements	Test Year 2018 Projected Removal Exp	Test Year 12/31/2018 Accumulated Depr (A)
		INTANGIBLE PLANT					
1	301	Organization	-	-	-	-	-
2	302	Franchise and Consents	-	-	-	-	-
3	303	Miscellaneous Intangible Plant	50,016,984	7,671,403	(6,715,756)	-	50,972,631
4		TOTAL INTANGIBLE PLANT	$ 50,016,984	$ 7,671,403	$ (6,715,756)	$ -	**$ 50,972,631**
5		PRODUCTION PLANT					
6		STEAM PRODUCTION					
7	310	Land and Land Rights	9,535	-	-	-	9,535
8	311	Structures and Improvements	269,699,989	9,759,540	(3,686,388)	(1,062,541)	274,710,600
9	312	Boiler Plant Equipment	789,109,605	29,171,707	(11,018,780)	(3,175,982)	804,086,550
10	314	Turbogenerator Units	236,228,258	8,597,925	(3,247,620)	(936,076)	240,642,486
11	315	Accessory Electric Equipment	71,912,238	2,654,903	(1,002,814)	(289,045)	73,275,282
12	316	Miscellaneous Power Plant Equipment	79,174,390	2,826,816	(1,067,751)	(307,761)	80,625,694
13	317	ARO Cost for Steam Production	10,365,010	367,529	(138,821)	(40,013)	10,553,705
14		TOTAL STEAM PRODUCTION	$ 1,456,499,024	$ 53,378,420	$ (20,162,175)	$ (5,811,418)	**$ 1,483,903,851**
15		OTHER PRODUCTION					
16	340	Land and Land Rights	-	-	-	-	-
17	341	Structures and Improvements	8,816,330	312,615	(118,082)	(34,035)	8,976,828
18	342	Fuel Holders. Products, and Accessories	-	-	-	-	-
19	343	Prime movers	-	-	-	-	-
20	344	Generators	21,973,615	779,154	(294,303)	(84,828)	22,373,637
21	345	Accessory Electric Equipment	1,513,180	53,655	(20,267)	(5,842)	1,540,726
22	346	Miscellaneous Power Plant Equipment	113,356	4,019	(1,518)	(438)	115,419
23	347	ARO Cost for Other Production	-	-	-	-	-
24		TOTAL OTHER PRODUCTION	$ 32,416,480	$ 1,149,443	$ (434,170)	$ (125,143)	**$ 33,006,611**
25		TOTAL PRODUCTION PLANT	$ 1,488,915,504	$ 54,527,863	$ (20,596,345)	$ (5,936,561)	**$ 1,516,910,462**
26		TRANSMISSION PLANT					
27	350	Land and Land Rights	27,254,614	962,273	(361,272)	(104,765)	27,750,850
28	352	Structures and Improvements	5,575,898	197,715	(74,679.98)	(21,526.00)	5,677,407
29	353	Station Equipment	171,470,536	6,080,115	(2,296,589)	(661,954)	174,592,108
30	354	Towers and Fixtures	27,834,357	986,970	(372,799)	(107,454)	28,341,074
31	355	Poles and Fixtures	161,698,937	5,733,626	(2,165,714)	(624,232)	164,642,617
32	356	Overhead Conductors and Devices	124,746,362	4,423,337	(1,670,790)	(481,577)	127,017,332
33	357	Underground Conduit	12,914	458	(173)	(50)	13,149
34	358	Underground Conductors and Devices	574	21	(7)	(1)	587
35	359	Roads and Trails	94,673	3,357	(1,268)	(365)	96,397
36		TOTAL TRANSMISSION PLANT	$ 518,688,866	$ 18,387,872	$ (6,943,293)	$ (2,001,924)	**$ 528,131,521**
37		DISTRIBUTION PLANT					

Southwestern Electric Power Company **WP B 2-6-1**
Test Year Rollfoward of Accumulated Depreciation
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Account	Plant	7/31/2018 Test Year Accumulated Depr	**Test Year** 2018 Projected Depr Exp	**Test Year** 2018 Projected Retirements	**Test Year** 2018 Projected Removal Exp	**Test Year** 12/31/2018 Accumulated Depr (A)
38	360	Land and Land Rights	2,364,869	83,496	(31,347)	(9,091)	2,407,927
39	361	Structures and Improvements	2,358,032	83,612	(31,582)	(9,103)	2,400,959
40	362	Station Equipment	87,227,172	3,092,958	(1,168,276)	(336,734)	88,815,121
41	364	Poles, Towers, and Fixtures	191,771,136	6,799,945	(2,568,487)	(740,326)	195,262,268
42	365	Overhead Conductors and Devices	154,898,443	5,492,491	(2,074,630)	(597,979)	157,718,325
43	366	Underground Conduit	25,318,278	897,752	(339,100)	(97,740)	25,779,190
44	367	Underground Conductors and Devices	98,679,999	3,499,059	(1,321,669)	(380,950)	100,476,439
45	368	Line Transformers	119,257,576	4,228,714	(1,597,277)	(460,389)	121,428,624
46	369	Services	39,223,885	1,390,825	(525,345)	(151,421)	39,937,945
47	370	Meters	(40,093,370)	(1,421,656)	536,991	154,779	(40,823,256)
48	371	Installation on Customer Premises	25,160,367	892,153	(336,986)	(97,131)	25,618,404
49	373	Street Lighting and Signal Systems	25,627,015	908,699	(343,236)	(98,932)	26,093,546
50		TOTAL DISTRIBUTION PLANT	$ 731,793,405	$ 25,948,048	$ (9,800,944)	$ (2,825,017)	**$ 745,115,493**
51		GENERAL PLANT					
52	389	Land and Land Rights	(192,917)	(6,810)	2,558	742	(196,427)
53	390	Structures and Improvements	42,854,248	1,519,554	(573,969)	(165,437)	43,634,396
54	391	Office Furniture and Equipment	6,516,539	146,197	(55,220)	(15,917)	6,591,599
55	392	Transportation Equipment	3,669,673	129,850	(49,047)	(14,137)	3,736,339
56	393	Stores Equipment	1,704,196	60,427	(22,825)	(6,578)	1,735,220
57	394	Tools, Shop and Garage Equipment	8,940,550	317,021	(119,744)	(34,514)	9,103,313
58	395	Laboratory Equipment	5,426,186	56,847	(21,472)	(6,189)	5,455,372
59	396	Power Operated Equipment	30,497	1,081	(408)	(117)	31,052
60	397	Communication Equipment	17,558,662	588,052	(222,119)	(64,026)	17,860,569
61	398	Miscellaneous Equipment	1,278,589	43,916	(16,588)	(4,781)	1,301,135
62	399	Other Tangible Property	74,822,846	2,527,864	(954,829)	(275,213)	76,120,668
63		TOTAL GENERAL PLANT	$ 162,609,067	$ 5,383,999	$ (2,033,664)	$ (586,167)	**$ 165,373,236**
64		TOTAL COMPANY Accumulated Depreciation	**$ 2,952,023,827** (a)	**$ 111,919,185**	**$ (46,090,001)**	**$ (11,349,669)**	**$ 3,006,503,342**

Purpose: Rollforward of test year accumulated depreciation.

Supporting Schedules and Workpapers:
(a) E-17 Part II B

Recap Schedule:
(A) Schedule B-2

Southwestern Electric Power Company
CWIP Closing not Included in Forecast Amounts
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP B 2-7

Line No.		Project	Description	12/31/2019 Balance	In Service Date
1	**Steam Generation Plant**	WLKCI2004	WLKCI2004: U2 SH&RH Outlet BNK&HDR Repl	6,470,055	12/7/2018
2		WSHCU0019	WSHCU0019 WSH U0 Coal Car Dumper Replace	2,371,333	12/31/2018
3		NRCPSWPCO	NRCPSWPCO NERC CIP SWEPCO	1,980,838	9/28/2018
4		FLCU10155	FLCU10155 FLC U1B, 4-kV Switchgear Repl	1,637,544	4/30/2018
5		WSHCU0CBK	WSHCU0CBK WSH CAP BANK 4KV Switchgr Rp	1,100,693	6/29/2018
6		FLCU10157	FLCU10157 FLC 4KV CH1A1B Switchgear Rpl	879,084	4/30/2018
7					
8			**Steam Generation Plant Sum**	14,439,547	
9					
10	**Transmission Plant**	A16806003	A16806003: Strklr Tap-Cedarville REC rebu	3,491,890	12/31/2018
11		A16806503	A16806503: Shadow for A16806003	2,894,978	12/21/2018
12		A15706C10	A15706C10 Shadow for A15706575	2,133,790	5/1/2018
13		A16806587	A16806587 Shadow for A16806525	1,331,188	4/27/2018
14		P15127501	P15127501 Shadow: SWEPCO P15127001	1,249,119	5/1/2018
15		A15706C44	A15706C44 Shadow For A15706C43	949,575	5/1/2018
16		A15706626	A15706626 T/SWEPCO/IPC 138 GCB 7340 Fail	947,610	11/30/2018
17		A16806516	A16806516 Shadow for A16806016	728,509	5/1/2018
18		A15706624	A15706624 Clarendon - Jericho 69kV strs	721,874	5/1/2018
19		A16806506	A16806506 Shadow for A16806006	701,124	5/1/2018
20		A16806536	A16806536 ROW: Mount Pleasant to DeKalb	524,555	5/18/2018
21		A16806593	A16806593: Shadow for A16806531	510,456	6/1/2019
22					
23			**Transmission Plant - Electric Sum**	16,184,668	
24					
25	**Distribution Plant**	A12102601	A12102601 D/SW/PurchNewMobile SW-15-TEX	2,612,041	6/30/2017
26		DN15S01F0	DN15S01F0: SEP/LAShrvpt Netwk Remed 2015	800,515	12/31/2018
27		000005644	000005644: Ds-SEP-La-Al Pole Replacement	587,633	12/31/2018
28					
29			**Distribution Plant - Electric Sum**	4,000,189	
30					
31	**Intangible Plant**				
32		IT1681421	IT1681421 Maximo Imp - SEP - G	4,153,458	12/31/2019
33		IT1591421	IT1591421 Maximo Imp - SEP - D	1,294,047	12/31/2019
34		IT1941421	IT1941421 Maximo Imp - SEP - T	969,748	12/31/2019
35		IT1611421	IT1611421 Maximo Imp - SEPT - D	666,410	12/31/2019
36		IT1111421	IT1111421 Maximo Imp - SEPT - T	500,689	12/31/2019
37				7,584,352	
38					
39					
40			**Total Incremental Rate Base Adjustment**	42,208,756	
41					
42					

Line No.	Plant	Composite Rate	Annual Depreciation	Accumulated Depreciation
45	Production	3.01%	433,935.40	650,903.10
46	Transmission	2.33%	377,126.95	565,690.42
47	Distribution	3.01%	120,292.44	180,438.67
48	Intangible	12.68%	961,736.91	1,442,605.37

Purpose: To increase rate base for addtionally identified incremental projects into plant-in-service

Supporting Schedules and Workpapers:
B-8

Recap Schedule:
F 1.3
B 2

Southwestern Electric Power Company
Derivation of Test Year Rate Base
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE B-3

Explanation: Schedule showing derivation of test year rate base

(1) Line No.	(2) Description	(3) Actual Amount per Trial Balance at End of Historical Portion of Test Year (a)	(5) Adjustments for Projected Portion of Test Year	(7) Total Projected Test Year Balance 12/31/2018
1	Gross Utility Plant in Service: (a)			
2	Intangible Plant			
3	301 Organization	12,202	0	12,202
4	302 Franchise and Consents	-	-	-
5	303 Miscellaneous Intangible Plant	97,658,520	24,565,366	122,223,886
6	TOTAL INTANGIBLE PLANT	97,670,722	24,565,366	122,236,088
7	Production			
8	STEAM PRODUCTION			
9	310 Land and Land Rights	26,969,480	(1)	26,969,479
10	311 Structures and Improvements	629,284,547	4,882,029	634,166,576
11	312 Boiler Plant Equipment	2,663,794,579	26,283,863	2,690,078,442
12	314 Turbogenerator Units	727,750,627	3,922,302	731,672,929
13	315 Accessory Electric Equipment	237,973,895	2,255,751	240,229,646
14	316 Miscellaneous Power Plant Equipment	214,848,118	2,015,510	216,863,628
15	317 ARO Cost for Steam Production	58,944,290	1	58,944,291
16	TOTAL STEAM PRODUCTION	4,559,565,536	39,359,455	4,598,924,991
17	OTHER PRODUCTION			
18	340 Land and Land Rights	1,451,852	(0)	1,451,852
18	341 Structures and Improvements	34,912,751	305,375	35,218,126
19	342 Fuel Holders. Products, and Accessories	-	-	-
19	343 Prime movers	-	-	-
20	344 Generators	84,008,692	734,807	84,743,499
20	345 Accessory Electric Equipment	8,994,738	78,676	9,073,414
21	346 Miscellaneous Power Plant Equipment	784,464	6,862	791,326
21	347 ARO Cost for Other Production	-	-	-
22	TOTAL OTHER PRODUCTION	130,152,498	1,125,719	131,278,217
23	TOTAL PRODUCTION PLANT	4,689,718,034	40,485,174	4,730,203,208
24	Transmission			
25	350 Land and Land Rights	97,320,963	2,232,229	99,553,192
25	352 Structures and Improvements	14,717,825	354,997	15,072,822
26	353 Station Equipment	619,251,082	14,936,485	634,187,567
26	354 Towers and Fixtures	40,872,806	985,862	41,858,668
27	355 Poles and Fixtures	647,359,524	15,614,468	662,973,992
27	356 Overhead Conductors and Devices	380,513,258	9,178,072	389,691,330
28	357 Underground Conduit	2,069,255	49,911	2,119,166
29	358 Underground Conductors and Devices	40,340	967	41,307
28	359 Roads and Trails	131,947	0	131,947
30	TOTAL TRANSMISSION PLANT	1,802,277,001	43,352,990	1,845,629,991
31	Distribution			
32	360 Land and Land Rights	11,419,206	(1)	11,419,205
33	361 Structures and Improvements	7,775,648	217,284	7,992,932
34	362 Station Equipment	307,422,114	8,590,676	316,012,790
35	364 Poles, Towers, and Fixtures	438,848,632	12,263,290	451,111,922

Southwestern Electric Power Company
Derivation of Test Year Rate Base
Test Year Ending December 31, 2018
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SCHEDULE B-3

Explanation: Schedule showing derivation of test year rate base

(1) Line No.	(2) Description	(3) Actual Amount per Trial Balance at End of Historical Portion of Test Year (a)	(5) Adjustments for Projected Portion of Test Year	(7) Total Projected Test Year Balance 12/31/2018
36	365 Overhead Conductors and Devices	439,915,586	12,293,105	452,208,690
37	366 Underground Conduit	66,522,478	1,858,920	68,381,398
38	367 Underground Conductors and Devices	219,395,395	6,130,837	225,526,232
39	368 Line Transformers	386,576,527	10,802,586	397,379,113
40	369 Services	90,906,356	2,540,308	93,446,664
41	370 Meters	84,378,024	2,357,880	86,735,904
42	371 Install on Customer's Premises	43,598,031	1,218,313	44,816,344
43	373 Street Lighting and Signal Systems	41,871,653	1,170,071	43,041,724
44	TOTAL DISTRIBUTION PLANT	2,138,629,650	59,443,268	2,198,072,918
44	General			
45	389 Land and Land Rights	18,643,207	0	18,643,207
46	390 Structures and Improvements	104,459,189	432,548	104,891,737
47	391 Office Furniture and Equipment	10,059,127	286	10,059,413
48	392 Transportation Equipment	4,118,518	0	4,118,518
49	393 Stores Equipment	2,994,676	12,400	3,007,076
50	394 Tools, Shop and Garage Equipment	26,341,827	109,077	26,450,904
51	395 Laboratory Equipment	5,501,275	0	5,501,275
52	396 Power Operated Equipment	759,763	0	759,763
53	397 Communication Equipment	36,404,311	148,802	36,553,113
54	398 Miscellaneous Equipment	2,596,116	10,750	2,606,866
55	399 Other Tangible Property	89,356,447	276,318	89,632,765
56	TOTAL GENERAL PLANT	301,234,453	990,184	302,224,637
57	Holding Company			
58	303 Misc. Intangible Plant	-	-	-
59	389 Land and Land Rights	-	-	-
60	390 Structures and Improvements	-	-	-
61	391 Office Furniture & Equipment	-	-	-
62	392 Transportation Equipment	-	-	-
63	393 Stores Equipment	-	-	-
64	395 Laboratory Equipment	-	-	-
65	396 Power Operated Equipment	-	-	-
66	397 Communication Equipment	-	-	-
67	398 Miscellaneous Equipment	-	-	-
68	TOTAL HOLDING COMPANY	-	-	-
69	Total Plant IN Service Test year ending 12/31/18	9,029,529,860	168,836,982	9,198,366,842
70	Less: Accumulated Depreciation: (a)			
71	301 Organization	-	-	-
72	302 Franchise and Consents	-	-	-
73	303 Miscellaneous Intangible Plant	50,016,984	955,647	50,972,631
	TOTAL INTANGIBLE PLANT	50,016,984	955,647	50,972,631
74	Production			

Southwestern Electric Power Company
Derivation of Test Year Rate Base
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE B-3

Explanation: Schedule showing derivation of test year rate base

(1) Line No.	(2) Description	(3) Actual Amount per Trial Balance at End of Historical Portion of Test Year (a)	(5) Adjustments for Projected Portion of Test Year	(7) Total Projected Test Year Balance 12/31/2018
75	STEAM PRODUCTION			
76	310 Land and Land Rights	9,535	-	9,535
77	311 Structures and Improvements	269,699,989	5,010,611	274,710,600
78	312 Boiler Plant Equipment	789,109,605	14,976,945	804,086,550
79	314 Turbogenerator Units	236,228,258	4,414,229	240,642,486
80	315 Accessory Electric Equipment	71,912,238	1,363,044	73,275,282
81	316 Miscellaneous Power Plant Equipment	79,174,390	1,451,304	80,625,694
82	317 ARO Cost for Steam Production	10,365,010	188,695	10,553,705
83	TOTAL STEAM PRODUCTION	1,456,499,024	27,404,827	1,483,903,851
84	OTHER PRODUCTION			
85	340 Land and Land Rights	-	-	-
86	341 Structures and Improvements	8,816,330	160,498	8,976,828
87	342 Fuel Holders. Products, and Accessories	-	-	-
88	343 Prime movers	-	-	-
89	344 Generators	21,973,615	400,023	22,373,637
90	345 Accessory Electric Equipment	1,513,180	27,546	1,540,726
91	346 Miscellaneous Power Plant Equipment	113,356	2,063	115,419
92	347 ARO Cost for Other Production	-	-	-
93	TOTAL OTHER PRODUCTION	32,416,480	590,130	33,006,611
94	TOTAL PRODUCTION PLANT	1,488,915,504	27,994,957	1,516,910,462
95	Transmission			
96	350 Land and Land Rights	27,254,614	496,236	27,750,850
97	352 Structures and Improvements	5,575,898	101,509	5,677,407
98	353 Station Equipment	171,470,536	3,121,572	174,592,108
99	354 Towers and Fixtures	27,834,357	506,717	28,341,074
100	355 Poles and Fixtures	161,698,937	2,943,680	164,642,617
101	356 Overhead Conductors and Devices	124,746,362	2,270,970	127,017,332
102	357 Underground Conduit	12,914	235	13,149
103	358 Underground Conductors and Devices	574	13	587
104	359 Road and Trails	94,673	1,724	96,397
105	TOTAL TRANSMISSION PLANT	518,688,866	9,442,655	528,131,521
105	Distribution			
106	360 Land and Land Rights	2,364,869	43,058	2,407,927
107	361 Structures and Improvements	2,358,032	42,927	2,400,959
108	362 Station Equipment	87,227,172	1,587,948	88,815,121
109	364 Poles, Towers, and Fixtures	191,771,136	3,491,132	195,262,268
110	365 Overhead Conductors and Devices	154,898,443	2,819,882	157,718,325
111	366 Underground Conduit	25,318,278	460,912	25,779,190
112	367 Underground Conductors and Devices	98,679,999	1,796,440	100,476,439
113	368 Line Transformers	119,257,576	2,171,048	121,428,624
114	369 Services	39,223,885	714,059	39,937,945
115	370 Meters	(40,093,370)	(729,886)	(40,823,256)
116	371 Install on Customer's Premises	25,160,367	458,036	25,618,404
117	373 Street Lighting and Signal Systems	25,627,015	466,531	26,093,546
118	TOTAL DISTRIBUTION PLANT	731,793,405	13,322,087	745,115,493
119	Regional Transmission and Market Operations			

Southwestern Electric Power Company
Derivation of Test Year Rate Base
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE B-3

Explanation: Schedule showing derivation of test year rate base

(1) Line No.	(2) Description	(3) Actual Amount per Trial Balance at End of Historical Portion of Test Year (a)	(5) Adjustments for Projected Portion of Test Year	(7) Total Projected Test Year Balance 12/31/2018
120	General			
121	389 Land and Land Rights	(192,917)	(3,510)	(196,427)
122	390 Structures and Improvements	42,854,248	780,148	43,634,396
123	391 Office Furniture and Equipment	6,516,539	75,060	6,591,599
124	392 Transportation Equipment	3,669,673	66,666	3,736,339
125	393 Stores Equipment	1,704,196	31,024	1,735,220
126	394 Tools, Shop and Garage Equipment	8,940,550	162,763	9,103,313
127	395 Laboratory Equipment	5,426,186	29,186	5,455,372
128	396 Power Operated Equipment	30,497	556	31,052
129	397 Communication Equipment	17,558,662	301,907	17,860,569
130	398 Miscellaneous Equipment	1,278,589	22,547	1,301,135
131	399 ARO General Plant	74,822,846	1,297,822	76,120,668
132	TOTAL GENERAL PLANT	162,609,067	2,764,168	165,373,236
144	Total Accumulated Depreciation 12-31-2018	2,952,023,827	54,479,515	3,006,503,342
145	Net Utility Plant in Service			
146	Plant Held for Future Use: (b)	1,291,835	-	1,291,835
147	Construction Work in Progress: (c)			
148	Production	42,914,520	(4,438,922)	38,475,598
149	Transmission	118,449,083	(3,429,735)	115,019,348
150	Distribution	26,764,524	(3,233,185)	23,531,339
151	General	17,691,120	1,835,237	19,526,357
152	Intangible Plant	7,948,709	3,963,497	11,912,206
153	Holding Company	-	-	-
154	Total	213,767,956	(5,303,108)	208,464,848
155	Working Capital Assets: (B) (totals only)	1,237,712,466	(38,831,219)	1,198,881,247
156	Other: (d)			
157	Non-Utility Property	-	-	-
158	Acquisition Adjustments	18,043,976	-	18,043,976
159	Acquisition Adjustment Amortization	(18,043,976)	-	(18,043,976)
160	Total	-	-	-
161	Total Rate Base	**7,530,278,290**	**70,223,140**	**7,600,501,430**

*Use this column only if the test period is partially projected

Supporting Schedules:
(a) E-17 Part II A, WP B 2-6-1
(b) Schedule B-7
(c) Schedule B-8
(d) Schedule B-10

Recap Schedules
(A) Schedule B-1
(B) Schedule B-4

Southwestern Electric Power Company
Derivation of Test Year Rate Base
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE B-3

Explanation: Schedule showing derivation of test year rate base

(1)	(2)	(3)	(5)	(7)
Line No.	Description	Actual Amount per Trial Balance at End of Historical Portion of Test Year (a)	Adjustments for Projected Portion of Test Year	Total Projected Test Year Balance 12/31/2018

Southwestern Electric Power Company
Calculation of Working Capital Assets
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE B-4

Explanation: Schedule showing calculation of working capital assets necessary to provide utility service. Column should include only asset accounts that meet the following criteria: (1) is necessary for providing utility service; (2) is not included elsewhere in rate base; (3) does not accrue income that is not included in operating revenue. [NOTE: Working capital may be calculated using either method I or II below; however, regardless of method chosen, information required for Method I shall be supplied]

I. Average Working Capital Assets Method
Excludes items included in ratebase

(1) Line No.	(2) Account Number	(3) Account Title	(4) Balance at end of Test year (a)	(5) Adj. Needed to Achieve 13-Month Average (B) (Col. 6 - Col. 4)	(6) 13 Month Average (a)	(7) Other Adjustment (B)	(8) Other Adjustment Ref. No. *(b)	(9) Pro Forma WCA (A) (Col. 6 + Col. 7)
1	1010006	Dolet Hills FAS 143 ARO Asset	41,520,820.72	(11,682,372)	29,838,448	(29,838,448)	(2)	-
2	1011001	Capital Leases	47,912,413.00	(266,954)	47,645,459			47,645,459
3	1011012	Accrued Capital Leases	124,546.00	122,984	247,530			247,530
4	1011006	Prov-Leased Assets	(21,116,832.00)	275,237	(20,841,595)			(20,841,595)
5	1080012	Dolet Hills FAS 143 ARO Deprec	(6,924,295.00)	252,308	(6,671,987)	6,671,987	(2)	-
6	1080013	ARO Removal Deprec - Accretion	6,859,481.00	(195,327)	6,664,154	(6,664,154)	(2)	-
7	1160007	OthElecPltAdjTurkImprmnt-EPIS	(57,889,147.00)	(402,093)	(58,291,240)	58,291,240	(5)	-
8	1160008	TurkAFUDCReverseTXCap-EPIS	(1,301,329.00)	(9,039)	(1,310,368)	1,310,368	(5)	-
9	1160009	AmortTurkImprmnt&AFUDCReversal	6,039,507.00	(152,844)	5,886,663	(5,886,663)	(5)	-
10	1160012	Turk Imprmnt-AuxBoiler	(18,334,484.00)	(127,350)	(18,461,834)	18,461,834	(5)	-
11	1160013	Turk Imprmnt-AuxBoiler Amort	1,963,124.00	(54,103)	1,909,021	(1,909,021)	(5)	-
12	1160016	TX Trans Veg Mgmt Cost Wrteoff	(1,428,161.00)	69,662	(1,358,499)	1,358,499	(5)	-
13	1160017	TX Distr Veg Mgmt Cost Wrteoff	(4,066,863.00)	(30,116)	(4,096,979)	4,096,979	(5)	-
14	1160018	TX Dist Veg Mgt WriteOff Amort	307,605.00	(17,665)	289,940	(289,940)	(5)	-
15	1160019	TX Tran Veg Mgt WriteOff Amort	60,094.00	(3,962)	56,132	(56,132)	(5)	-
16	1160020	TX Trans Costs - SERP	(158,096.00)	(28,045)	(186,141)	186,141	(5)	-
17	1160021	TX Distr Costs - SERP	(47,384.00)	(14,430)	(61,814)	61,814	(5)	-
18	1160022	TX Gen Costs - SERP	(298,269.00)	(433,492)	(731,761)	731,761	(5)	-
19	1160023	TX CWIP FinBased Incen - Trans	(1,731,712.00)	160,628	(1,571,084)	1,571,084	(5)	-
20	1160024	TX CWIP FinBased Incen - Distr	(2,088,180.00)	178,192	(1,909,988)	1,909,988	(5)	-
21	1160025	TX CWIP FinBased Incen - Gen	(2,446,044.00)	192,818	(2,253,226)	2,253,226	(5)	-
22	1160026	TX RWIP FinBased Incen - Trans	(63,326.00)	4,838	(58,488)	58,488	(5)	-
23	1160027	TX RWIP FinBased Incen - Distr	(83,911.00)	7,593	(76,318)	76,318	(5)	-
24	1160028	TX RWIP FinBased Incen - Gen	(93,250.00)	6,840	(86,410)	86,410	(5)	-
25	1230000	Invest Nonconsol Assoc Co	1,075,785.00	(787,949)	287,836	(287,836)		-
26	1231003	Capital Contributions to Subs	100,000.00	-	100,000	(100,000)		-
27	1231005	Invest in Subs Retained Erngs	1,892,064.00	(6,250)	1,885,814	(1,885,814)		-
28	1231101	Invest Nonconsol Subs-Equity	24,759,407.00	(0)	24,759,407	(7,298,078)	WP B 4-5	17,461,329
29	1231102	Equity in Erngs Nonconsol Subs	13,766,159.00	(478,874)	13,287,285	(13,287,285)		-
30	1240002	Oth Investments-Nonassociated	1,833,009.00	(733,846)	1,099,163	(1,099,163)	(1)	-
31	1240027	Other Property - RWIP	3,498.00	(1,424)	2,074	(2,074)	(1)	-
32	1240029	Other Property - CPR	301,444.00	(0)	301,444	(301,444)	(1)	-

Southwestern Electric Power Company
Calculation of Working Capital Assets
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE B-4

Explanation: Schedule showing calculation of working capital assets necessary to provide utility service. Column should include only asset accounts that meet the following criteria: (1) is necessary for providing utility service; (2) is not included elsewhere in rate base; (3) does not accrue income that is not included in operating revenue. [NOTE: Working capital may be calculated using either method I or II below; however, regardless of method chosen, information required for Method I shall be supplied]

I. Average Working Capital Assets Method
Excludes items included in ratebase

(1) Line No.	(2) Account Number	(3) Account Title	(4) Balance at end of Test year (a)	(5) Adj. Needed to Achieve 13-Month Average (B) (Col. 6 - Col. 4)	(6) 13 Month Average (a)	(7) Other Adjustment (B)	(8) Other Adjustment Ref. No. *(b)	(9) Pro Forma WCA (A) (Col. 6 + Col. 7)
33	1290001	Non-UMWA PRW Funded Position	27,855,898.00	789,911	28,645,809			28,645,809
34	1290002	SFAS 106 - Non-UMWA PRW	4,207,041.00	(1,294,731)	2,912,310			2,912,310
35	1310000	Cash	1,625,000.00	136,310	1,761,310			1,761,310
36	1340018	Spec Deposits - Elect Trading	4,560,652.00	(2,401,797)	2,158,855			2,158,855
37	1340046	Deposits-O&M Dolet Hills Plant	3,348,000.00	1,274,128	4,622,128			4,622,128
38	1340048	Spec Deposits-Trading Contra	49,036.00	35,114	84,150			84,150
39	1340050	Spec Deposit Mizuho Securities	-	-	-			-
40	1340051	Spec Depost RBC	37,411.00	(11,889)	25,522			25,522
41	1340053	Deposits - Flexible Spending	90,164.00	0	90,164			90,164
42	1420001	Customer A/R - Electric	137,139,619.00	(18,008,098)	119,131,521			119,131,521
43	1420006	A/R-Customer Assistance	-	127	127			127
44	1420014	Customer A/R-System Sales	15,272,820.00	442,012	15,714,832			15,714,832
45	1420022	Cust A/R - Factored	(144,670,792.00)	22,086,920	(122,583,872)	122,583,872	(2)	-
46	1420023	Cust A/R-System Sales - MLR	251,008.00	(115,956)	135,052			135,052
47	1420044	Customer A/R - Estimated	20,640,333.00	6,171,222	26,811,555			26,811,555
48	1420048	Emission Allowance Trading	-	54	54			54
49	1420051	MISO AR Accrual	-	25,052	25,052			25,052
50	1420055	SPP AR Accrual	-	2,670,103	2,670,103			2,670,103
51	1420101	Other Accounts Rec - Cust	563,033.00	(88,192)	474,841			474,841
52	1420102	AR Peoplesoft Billing - Cust	5,554,690.00	373,451	5,928,141			5,928,141
53	1430002	Allowances	20.00	8	28			28
54	1430022	2001 Employee Biweekly Pay Cnv	7,629.00	(0)	7,629			7,629
55	1430080	Jointly Owned Unit O&M Billing	18,340,069.00	(1,619,161)	16,720,908	(3,826,689)	WP B 4-1	12,894,219
56	1430081	Damage Recovery - Third Party	80,593.00	(8,544)	72,049			72,049
58	1430086	AR Accrual NYMEX OTC Penults	-	0	0			0
59	1430101	Other Accounts Rec - Misc	950,297.00	253,427	1,203,724	(463,562)	WP B 4-1	740,162
60	1430102	AR Peoplesoft Billing - Misc	931,407.00	598,146	1,529,553			1,529,553
61	1430103	AR Long-Term-Miscellaneous	901,365.00	149,339	1,050,704			1,050,704
62	1440002	Uncoll Accts-Other Receivables	(557,715.00)	(129,610)	(687,325)			(687,325)
63	1450000	Corp Borrow Prg (NR-Assoc)	-	82,725,249	82,725,249	(82,725,249)	(1)	-
64	1460001	A/R Assoc Co - InterUnit G/L	27,115,186.00	(2,555,299)	24,559,887	(24,559,887)	(2)	-
65	1460004	A/R Assoc Co - CM Bills	31,878.00	17,708	49,586	(49,586)	(2)	-

Southwestern Electric Power Company
Calculation of Working Capital Assets
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE B-4

Explanation: Schedule showing calculation of working capital assets necessary to provide utility service. Column should include only asset accounts that meet the following criteria: (1) is necessary for providing utility service; (2) is not included elsewhere in rate base; (3) does not accrue income that is not included in operating revenue. [NOTE: Working capital may be calculated using either method I or II below; however, regardless of method chosen, information required for Method I shall be supplied]

I. Average Working Capital Assets Method
Excludes items included in ratebase

(1) Line No.	(2) Account Number	(3) Account Title	(4) Balance at end of Test year (a)	(5) Adj. Needed to Achieve 13-Month Average (B) (Col. 6 - Col. 4)	(6) 13 Month Average (a)	(7) Other Adjustment (B)	(8) Other Adjustment Ref. No. *(b)	(9) Pro Forma WCA (A) (Col. 6 + Col. 7)
66	1460006	A/R Assoc Co - Intercompany	1,517,769.00	(793,310)	724,459	(724,459)	(2)	-
67	1460009	A/R Assoc Co - InterUnit A/P	22,948.00	(7,441)	15,507	(15,507)	(2)	-
68	1460011	A/R Assoc Co - Multi Pmts	10,323,653.00	(2,676,326)	7,647,327	(7,647,327)	(2)	-
69	1460025	Fleet - M4 - A/R	16,583.00	6,612	23,195	(23,195)	(2)	-
70	1510001	Fuel Stock - Coal	44,950,375.00	(2,306,144)	42,644,231	(19,136,139)	WP B 4-2	23,508,092
71	1510002	Fuel Stock - Oil	4,591,541.00	(269,353)	4,322,188			4,322,188
72	1510016	Coal Inv on Hand Transp	12,202.00	713	12,915			12,915
73	1510017	Lignite Inv on Hand Inc Transp	27,136,700.00	2,653,332	29,790,032	7,366,385	WP B 4-2	37,156,417
74	1510018	Coal Survey Adjustment	(901,750.00)	177,506	(724,244)			(724,244)
75	1510020	Fuel Stock Coal - Intransit	3,850,121.00	(646,160)	3,203,961			3,203,961
76	1520000	Fuel Stock Exp Undistributed	2,167,938.00	(143,479)	2,024,459	(2,024,459)	(2)	-
77	1540001	M&S - Regular	66,526,150.00	(302,317)	66,223,833	(2,135,511)	WP B 4-1	64,088,322
78	1540004	M&S - Exempt Material	516,794.00	21,043	537,837	(45,519)	WP B 4-1	492,318
79	1540006	M&S - Lime and Limestone	1,403,684.00	(66,853)	1,336,831	(467,293)	WP B 4-1	869,538
80	1540013	Transportation Inventory	87,066.00	(7,483)	79,583			79,583
81	1540025	Matls Supply-Activated Carbon	298,572.00	49,104	347,676	(45,124)	WP B 4-1	302,552
82	1540028	M&S - Anhydrous Ammonia	18,579.00	3,066	21,645	(29,128)	WP B 4-1	(7,483)
83	1540030	Matls Supply-Calcium Bromide	57,671.00	(317)	57,354			57,354
84	1581012	CSAPR An. NOx Inv. - Current	(99,768.00)	65,838	(33,930)			(33,930)
85	1581014	CSAPR Seas NOx Comp Inv - Curr	112,608.00	(9,670)	102,938			102,938
86	1630004	Strs Exp-T&D Satellite Storerm	-	(0)	(0)			(0)
87	1630056	Knox Lee Power Plant	-	0	0			0
88	1630059	Pirkey Power Plant	-	(0)	(0)			(0)
89	1630061	Welsh Power Plant	-	0	0			0
90	1650001	Prepaid Insurance	2,063,567.00	(661,426)	1,402,141			1,402,141
91	165000218	Prepaid Taxes	-	219,003	219,003			219,003
92	1650005	Prepaid Employee Benefits	-	6,698	6,698			6,698
93	1650006	Other Prepayments	16,914,734.00	21,736	16,936,470			16,936,470
94	1650009	Prepaid Carry Cost-Factored AR	179,617.00	(2,448)	177,169			177,169
95	1650010	Prepaid Pension Benefits	90,896,301.15	1,448,581	92,344,882			92,344,882
96	165000218	Prepaid Taxes	1,125,105.00	(605,826)	519,279			519,279
97	165001116	Prepaid Sales Taxes	-	-	-			-
98	165001117	Prepaid Sales Taxes	-	(76,652)	(76,652)			(76,652)
99	165001118	Prepaid Sales Taxes	1,225,200.00	5,658	1,230,858			1,230,858
100	165001216	Prepaid Use Taxes	-	-	-			-
101	165001217	Prepaid Use Taxes	-	1,545	1,545			1,545

Southwestern Electric Power Company
Calculation of Working Capital Assets
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE B-4

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I. Average Working Capital Assets Method
Excludes items included in ratebase

(1) Line No.	(2) Account Number	(3) Account Title	(4) Balance at end of Test year (a)	(5) Adj. Needed to Achieve 13-Month Average (B) (Col. 6 - Col. 4)	(6) 13 Month Average (a)	(7) Other Adjustment (B)	(8) Other Adjustment Ref. No. *(b)	(9) Pro Forma WCA (A) (Col. 6 + Col. 7)
102	165001218	Prepaid Use Taxes	159.00	2,575	2,734			2,734
103	165001316	Prepaid Local Franchise Taxes	-	-	-			-
104	165001317	Prepaid Local Franchise Taxes	-	4,451	4,451			4,451
105	165001318	Prepaid Local Franchise Taxes	53,575.00	(3,098)	50,477			50,477
106	1650014	FAS 158 Qual Contra Asset	(90,896,301.15)	(1,448,581)	(92,344,882)	92,344,882	WP B 4-3	-
107	1650016	FAS 112 ASSETS	-	-	-			-
108	1650017	Prepayment - Coal	4,200,175.00	734,857	4,935,032			4,935,032
109	1650018	Affl Trans Intercon Providers	-	(0)	(0)			(0)
110	1650021	Prepaid Insurance - EIS	3,126,986.00	(1,058,182)	2,068,804			2,068,804
111	1650023	Prepaid Lease	183,784.00	4,031	187,815			187,815
112	1650029	Future Wetlands Credits L-T	300,000.00	-	300,000			300,000
113	1650030	Other Prepayments - Long Term	1,709,806.00	(383,330)	1,326,476			1,326,476
114	1650035	PRW Without MED-D Benefits	27,734,881.02	(1,294,731)	26,440,150			26,440,150
115	1650037	FAS158 Contra-PRW Exclud Med-D	(27,734,881.02)	1,294,731	(26,440,150)	18,849,716	WP B 4-3	(7,590,434)
116	1710010	Interest Under Recover - LA	-	-	-			-
117	1710048	Interest Receivable -FIT -LT	(19,483.00)	9,825	(9,658)	9,658	(2)	-
118	1710348	Interest Receivable -SIT -LT	-	-	-			-
119	1720000	Rents Receivable	945,419.00	(61,009)	884,410	(884,410)	(4)	-
120	1730003	Acrd Utility Rev-West	56,833,992.00	(10,675,951)	46,158,041			46,158,041
121	1740000	Misc Current & Accrued Assets	-	6,246	6,246			6,246
122	1750001	Curr. Unreal Gains - NonAffil	7,768,208.00	(1,839,699)	5,928,509	(5,928,509)	(1)	-
123	1750002	Long-Term Unreal Gns - Non Aff	11,622.00	985	12,607	(12,607)	(1)	-
124	1750021	S/T Asset MTM Collateral	(46,143.00)	(34,952)	(81,095)	81,095	(1)	-
125	1750022	L/T Asset MTM Collateral	(2,893.00)	(162)	(3,055)	3,055	(1)	-
126	1810002	Unamort Debt Exp - Inst Pur Cn	29,813.00	2,941	32,754	(32,754)	(2)	-
127	1810003	Unamort Debt Exp Notes Payable	359,243.00	(66,415)	292,828	(292,828)	(2)	-
128	1810006	Unamort Debt Exp - Sr Unsec Nt	19,781,500.00	(4,220,093)	15,561,407	(15,561,407)	(2)	-
129	1810102	Unamort Debt Exp-PCB Ins	-	2,967	2,967	(2,967)	(2)	-
130	1823000	Other Regulatory Assets	2,652,987.00	(1,150,986)	1,502,001	(1,502,001)	(5)	-
131	1823010	Energy Efficiency Recovery	2,276,736.00	604,216	2,880,952	(2,880,952)	(5)	-
132	1823075	Def Exp Selling Price Variance	2,953,595.00	(1,078,084)	1,875,511	(1,875,511)	(5)	-
133	1823077	Unreal Loss on Fwd Commitments	1,171,267.00	(249,553)	921,714	(921,714)	(5)	-
134	1823099	Asset Retirement Obligations	5,200,318.00	(187,003)	5,013,315	(5,013,315)	(5)	-
135	1823108	Reg Asset - Rate Case Expenses	5,287,676.00	596,430	5,884,106	(5,884,106)	(5)	-
136	1823149	Unrecovered Fuel Cost - LA	-	496,052	496,052	(496,052)	(5)	-
137	1823150	Unrecovered Fuel Cost - AR	82,904.00	9,328,946	9,411,850	(9,411,850)	(5)	-
138	1823165	REG ASSET FAS 158 QUAL PLAN	92,570,059.00	1,802,255	94,372,314	(94,372,314)	(5)	-

Southwestern Electric Power Company
Calculation of Working Capital Assets
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE B-4

Explanation: Schedule showing calculation of working capital assets necessary to provide utility service. Column should include only asset accounts that meet the following criteria: (1) is necessary for providing utility service; (2) is not included elsewhere in rate base; (3) does not accrue income that is not included in operating revenue. [NOTE: Working capital may be calculated using either method I or II below; however, regardless of method chosen, information required for Method I shall be supplied]

I. Average Working Capital Assets Method
Excludes items included in ratebase

(1) Line No.	(2) Account Number	(3) Account Title	(4) Balance at end of Test year (a)	(5) Adj. Needed to Achieve 13-Month Average (B) (Col. 6 - Col. 4)	(6) 13 Month Average (a)	(7) Other Adjustment (B)	(8) Other Adjustment Ref. No. *(b)	(9) Pro Forma WCA (A) (Col. 6 + Col. 7)
139	1823166	REG ASSET FAS 158 OPEB PLAN	(2,310,642.00)	(512,235)	(2,822,877)	2,822,877	(5)	-
140	1823167	REG Asset FAS 158 SERP Plan	1,086,923.00	20,943	1,107,866	(1,107,866)	(5)	-
141	1823180	Deferred Storm Expense	-	(0)	(0)			(0)
142	1823219	Under Recovered EAC - LA	878.00	69,233	70,111	(70,111)	(5)	-
143	1823241	Valley District Due Diligence	-	3,811	3,811	(3,811)	(5)	-
144	1823299	SFAS 106 Medicare Subsidy	3,377,721.00	129,839	3,507,560			3,507,560
145	1823301	SFAS 109 Flow Thru Defd FIT	69,501,853.00	92,492	69,594,345	(38,292,893)	WP B 2-5-2	31,301,452
146	1823302	SFAS 109 Flow Thru Defrd SIT	191,121,231.00	(417,778)	190,703,453			190,703,453
147	1823306	Net CCS FEED Study Costs	441,067.00	7,134	448,201			448,201
148	1823324	LA FRP Asset	118,600.00	18,107	136,707	(136,707)	(5)	-
149	1823348	Louisiana Vegetation Managemnt	-	(0)	(0)			(0)
150	1823359	SWEPCo Transmission Recovery	2,416,572.00	401,071	2,817,643			2,817,643
151	1823360	2010 Severance Costs	-	31,147	31,147			31,147
152	1823374	Environmental Chemical Cost-AR	2,675,825.00	(161,750)	2,514,075			2,514,075
153	1823377	NBV - AROs Retired Plants	497,508.00	6,303	503,811			503,811
154	1823424	LA 2015 FRP Asset-SPP Deferral	5,029,196.00	(54,998)	4,974,198	(4,974,198)	(5)	-
155	1823425	LA 2015 FRP Asset - Contra	(274,514.00)	46,660	(227,854)	227,854	(5)	-
156	1823428	Welsh 2 TX Portion Undepr Bal	17,068,496.00	260,023	17,328,519	(17,328,519)	(5)	-
157	1823539	Facilities Maint SWEPCO LA	657,070.00	(30,162)	626,908	(626,908)	(5)	-
158	1823554	WELSH/FLINT CREEK ENVIRONM DI	22,304,030.00	520,255	22,824,285	(22,824,285)	(5)	-
159	1823555	WELSH/FLINTCREEK ENVIR-CONTR	(7,801,319.00)	(181,970)	(7,983,289)	7,983,289	(5)	-
160	1830000	Prelimin Surv&Investgtn Chrgs	1,668,269.00	(223,591)	1,444,678			1,444,678
161	1840002	Accounts Pay Adj - Clearing	(3,195.00)	1,717	(1,478)			(1,478)
162	1840019	CMS & CMF - Clearing Activity	-	(0)	(0)			(0)
163	1840033	Alliance Rail Car - OH	101,172.00	(31,285)	69,887			69,887
164	1840035	IT Oper Company (OPCO) Clearng	-	(0)	(0)			(0)
165	1860001	Allowances	1,417.00	149	1,566			1,566
166	1860002	Deferred Expenses	(11,569.00)	(69,147)	(80,716)			(80,716)
167	186000316	Deferred Property Taxes	-	-	-			-

Southwestern Electric Power Company
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Test Year Ending December 31, 2018
Docket No. 19-008-U

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I. Average Working Capital Assets Method
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(1) Line No.	(2) Account Number	(3) Account Title	(4) Balance at end of Test year (a)	(5) Adj. Needed to Achieve 13-Month Average (B) (Col. 6 - Col. 4)	(6) 13 Month Average (a)	(7) Other Adjustment (B)	(8) Other Adjustment Ref. No. *(b)	(9) Pro Forma WCA (A) (Col. 6 + Col. 7)
168	186000318	Deferred Property Taxes	(683,284.00)	27,747,235	27,063,951			27,063,951
169	1860005	Unidentified Cash Receipts	(100.00)	(219)	(319)			(319)
170	1860007	Billings and Deferred Projects	3,747,320.00	109,234	3,856,554	(218)	WP B 4-1	3,856,336
171	1860015	Billings Paid Union Benefits	2,473.00	106	2,579			2,579
172	1860046	Railroad Cars Subleased	7,848.00	(855)	6,993	(62,420)	WP B 4-1	(55,426)
173	1860077	Agency Fees - Factored A/R	4,001,984.00	(534,911)	3,467,073			3,467,073
174	186008118	Defd Property Tax - Cap Lease	(1,873.00)	74,632	72,759			72,759
175	1860089	Reclamation Advance	13,408,216.00	1,345,591	14,753,807			14,753,807
176	1860150	Deferred Rate Case Expense	92,948.00	(4,052)	88,896	(88,896)	(5)	-
177	1860153	Unamortized Credit Line Fees	373,946.00	37,501	411,447			411,447
178	1860154	Affl Deferred Tran(IPP) Credit	-	-	-			-
179	1860156	Sabine Mine Rusk Preparation	13,483,531.00	103,580	13,587,111			13,587,111
180	1860160	Deferred Expenses - Current	424,484.00	(103,350)	321,134	(37,394)	WP B 4-1	283,740
181	1860166	Def Lease Assets - Non Taxable	16,971.00	54,231	71,202			71,202
182	1860171	Marshall South Mine Prep	-	4,094	4,094			4,094
183	1860185	Long Term Assoc AR	1,266,807.00	(584,680)	682,127			682,127
184	1890001	Loss Recqd Debt - FMB	2,175,507.00	79,239	2,254,746	(2,254,746)	(2)	-
185	1890002	Loss Rec Debt-Ins Purch Cont	154,531.00	16,572	171,103	(171,103)	(2)	-
186	1890004	Loss Rec Debt-Debentures	1,896,069.00	79,095	1,975,164	(1,975,164)	(2)	-
187	1900011	ADIT Federal Non-UMWA PRW OCI	(417,286.00)	(63,213)	(480,499)	480,499	(2)	-
188	1900015	ADIT-Fed-Hdg-CF-Int Rate	1,626,300.00	81,414	1,707,714	(1,707,714)	(2)	-

Southwestern Electric Power Company
Calculation of Working Capital Assets
Test Year Ending December 31, 2018
Docket No. 19-008-U

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189	1901001	Accum Deferred FIT - Other	65,590,231.00	(752,684)	64,837,547	(64,837,547)	(2)	-
190	1901002	Accum Deferred SIT - Other	47,097,817.00	520,787	47,618,604	(47,618,604)	(2)	-
191	1902001	Accum Defd FIT - Oth Inc & Ded	673,975.00	290,834	964,809	(964,809)	(2)	-
192	1903001	Acc Dfd FIT - FAS109 Flow Thru	41,633,476.00	(19,300)	41,614,176	(41,614,176)	(2)	-
193	1904001	Accum Dfd FIT - FAS 109 Excess	148,407,966.00	555,694	148,963,660	(148,963,660)	(2)	-
194		Total Working Capital Assets	1,198,881,247	93,576,466	1,292,457,713	(403,680,412)	(2)	888,777,301
					(310,103,946)	(A)		(A)

* Adjustment Reason:
(1) Non-Utility
(2) Provided for elsewhere in the Cost of Service
(3) Interest-Bearing and income not included in operating revenue
(4) 13-Month Average is not representative of normal account balance
(5) 100% other jurisdiction

Supporting Schedules and Workpapers:
(a) Schedule B-5
(b) WP B 4-1, WP B 4-2, WP B 4-3. WP B 2-5-2

Recap Schedules
(A) Schedule B-1
(B) Schedule B-2

II. Lead-Lag Study Method
No lead lag study was performed.

Southwestern Electric Power Company **WP B 4-1**
Remove Turk Plant Related Working Capital Assets
Test Year Ending December 31, 2018
Docket No. 19-008-U

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Line No.	**Account**	**Description**	**2017 Dec**	**2018 Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Projected Aug**	**Projected Sep**	**Projected Oct**	**Projected Nov**	**Projected Dec**	**13-Month Average (A)**
1	1430080	Jointly Owned Unit O&M Billing	3,514,872	3,272,095	4,834,457	3,226,744	2,939,217	1,761,432	3,499,522	3,086,713	3,428,418	4,222,591	4,832,278	5,326,475	5,802,150	3,826,689
2	1430101	Other Accounts Rec - Misc	(32,442)	201,451	128,835	(40,721)	608,896	631,359	161,514	72,753	149,134	483,207	663,233	1,238,889	1,760,198	463,562
3	1510001 [(1)]	Fuel Stock - Coal	9,383,277	9,000,389	10,075,513	9,372,847	8,463,260	10,277,525	9,638,992	13,055,142	11,672,108	9,962,244	9,962,244	9,962,244	9,962,244	
4	1510018 [(1)]	Coal Survey Adjustment	(679,356)	(509,517)	(339,678)	(169,839)	-	(0)	(0)	(0)	-	-	-	-	-	
5	1510020 [(1)]	Fuel Stock Coal - Intransit	607,961	604,383	604,609	607,410	-	1,153,927	2,397,764	648,907	387,704	1,252,984	1,252,984	1,252,984	1,252,984	
6	1520000 [(1)]	Fuel Stock Exp Undistributed	(1,081,586)	(1,077,665)	(1,109,296)	(1,173,404)	(1,223,167)	(1,112,173)	(1,199,109)	(1,222,554)	(1,253,929)	(1,257,290)	(980,454)	(703,589)	(426,339)	
7	1540001	M&S - Regular	2,258,613	2,171,346	2,183,245	2,156,164	2,130,557	1,880,179	2,136,398	2,124,663	2,133,802	2,146,669	2,146,669	2,146,669	2,146,669	2,135,511
8	1540004	M&S - Exempt Material	58,205	59,971	59,201	59,774	60,100	37,780	36,624	38,183	34,805	36,776	36,776	36,776	36,776	45,519
9	1540006	M&S - Lime and Limestone	489,965	470,705	471,794	534,753	454,085	462,642	457,011	409,082	444,864	469,978	469,978	469,978	469,978	467,293
10	1540025	Matls Supply-Activated Carbon	33,698	55,025	24,620	61,102	38,249	75,421	55,216	27,578	61,081	38,655	38,655	38,655	38,655	45,124
11	1540028	M&S - Anhydrous Ammonia	13,042	31,691	17,840	28,753	2,766	43,828	31,987	18,579	39,021	37,789	37,789	37,789	37,789	29,128
12	1830000	Other Regulatory Assets	-	-	-	-	-	13,716	24,742	28,962	28,962	-	-	-	-	7,414
13	1860007	Billings and Deferred Projects	944	944	944	-	-	-	-	-	-	-	-	-	-	218
14	1860046	Railroad Cars Subleased	62,420	62,420	62,420	62,420	62,420	62,420	62,420	62,420	62,420	62,420	62,420	62,420	62,420	62,420
15	1860160	Deferred Expenses - Current	35,197	41,712	26,991	61,986	41,856	15,423	44,416	45,378	52,681	30,122	30,122	30,122	30,122	37,394
16		**Total**														**7,120,272**

Purpose: To remove Turk plant working capital assets identified from SWEPCO's actual and forecast ledgers. The amounts charged to Turk's department represent working capital assets associated with Turk.

(1) These fuel related accounts are removed separately as part of the fuel inventory adjustment (WP B 4-2)(B).

Note:
Sourced directly from Company's actual and forecast data based on Turk's department values 12810, 12901, 12902, 12903,12959,13141. Additional supporting files provided electronically.

Supporting Schedules:

Recap Schedule:
(A) B-4
(B) WP B 4-2

Southwestern Electric Power Company
Adjust Coal and Lignite 13-month Average Target Inventory
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP B 4-2

Line No.	(1)	(2) Total 151 and 152 [a] $ Amount [3] Excluding Oil	(3) Coal [1] Tons	(4) Coal [1] $ Amount [3](b) (Includes Turk)	(5) Turk Coal [2] Tons	(6) Turk Coal [2] $ Amount	(7)	(8) Lignite Inventory Tons	(9) Lignite Inventory $ Amount [3](b)
1	Dec 2017	$ 77,725,721	1,010,816	$ 37,504,947	265,472	$ 9,745,463		537,071	$ 40,220,773
2	Jan 2018	$ 73,885,572	974,880	$ 37,660,901	257,719	9,566,574		530,486	$ 36,224,671
3	Feb 2018	$ 76,009,688	1,211,291	$ 46,083,456	288,592	10,813,403		455,519	$ 29,926,231
4	Mar 2018	$ 78,897,776	1,281,410	$ 49,705,914	259,728	10,274,423		451,171	$ 29,191,862
5	Apr 2018	$ 75,473,770	1,236,302	$ 44,827,703	243,296	8,907,478		476,342	$ 30,646,068
6	May 2018	$ 79,389,034	1,308,355	$ 48,394,541	290,614	10,868,406		488,117	$ 30,994,493
7	Jun 2018	$ 78,991,011	1,229,535	$ 48,802,278	277,266	12,578,795		496,398	$ 30,188,733
8	Jul 2018	$ 78,842,118	1,305,961	$ 50,603,869	362,923	14,252,666		491,517	$ 28,238,249
9	Aug 2018 (projected)	$ 80,233,584	1,362,598	$ 53,099,523	320,984	13,075,958		471,544	$ 27,134,061
10	Sep 2018 (projected)	$ 75,713,583	1,389,969	$ 52,337,627	269,163	11,219,187		476,220	$ 23,375,956
11	Oct 2018 (projected)	$ 74,746,586	1,208,932	$ 47,520,131	272,626	11,620,513		464,059	$ 27,226,455
12	Nov 2018 (projected)	$ 73,243,584	1,214,511	$ 40,913,001	304,071	10,998,911		537,344	$ 32,330,583
13	Dec 2018 (projected)	$ 77,215,586	1,270,317	$ 41,212,992	323,993	11,394,715		544,501	$ 36,002,594
14	13-Month Average		1,231,144	46,051,299	287,418.97	11,178,192		493,868	30,900,056
15	Requested volume level		925,093		229,933			584,305	
16	Average Projected Price/Unit		$ 39.46		$ 41.69			$ 65.49	
17	Projected Inventory Costs			36,501,488					38,266,441
18	Adjustment from 13-Month Average to Target			(9,549,811)					7,366,385
19	Adjustment to Remove Turk from 13-Month Target					(9,586,328)			
20	**Total Adjustment Coal & Lignite**						**(19,136,139)**		**7,366,385**
21			Price Per Ton		Price Per Ton			Price Per Ton	
22	Jan 2019 (projected)		$ 38.25		$ 40.99			$ 65.70	
23	Feb 2019 (projected)		39.22		41.71			62.78	
24	Mar 2019 (projected)		39.72		42.09			65.91	
25	Apr 2019 (projected)		39.72		42.10			67.51	
26	May 2019 (projected)		39.69		41.14			67.47	
27	Jun 2019 (projected)		40.14		42.12			63.57	
28	Average Projected Price/Unit		$ 39.46		$ 41.69			$ 65.49	

Purpose: Adjust Coal and Lignite 13-month to target.

[1] Dolet Hills and Perkey balances reflect SWPCo's ownership portion. No ownership adjustment is required.

[2] Turk uses natural gas for startup and stabilization; no inventory is maintained. No additional fuel adjustment is required.

[3] Amounts do not tie to B-5 due to the allocaiton of 1510018, 1510020 and 1520000 which are allocated on this workpaper based on actual fuel. See w/p B 4-7 for reconciliation in total.

Supporting Schedules:
[a] B-5

Recap Schedules:
B-4

Southwestern Electric Power Company
Remove FAS 158 Prepayment Contra Assets
Test Year Ending December 31, 2018
Docket No. 19-008-U

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	**Account**	**Description**	**2017 Dec**	**2018 Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Projected Aug**	**Projected Sep**
1	1650014	FAS 158 Qual Contra Asset	(95,630,493)	(94,919,108)	(94,207,723)	(93,601,554)	(92,925,241)	(92,248,927)	(91,572,614)	(90,896,301)	(90,896,301)	(90,896,301)
2	1650037	FAS158 Contra-PRW Exclud Med-D	(23,527,840)	(24,131,784)	(24,735,728)	(25,343,014)	(25,919,707)	(26,524,765)	(27,129,823)	(27,734,881)	(27,734,881)	(27,734,881)
3		Total										
4		**Reduce adjustment by amount related to Turk:**										
5		[1] Total Turk Labor	7,885,273 (b)									
6		[1] Total SWEPCo Labor	123,399,067 (b)									
7		Turk portion of SWEPCo labor		6.3901% (b)								
8		Amount of Turk's portion of SWEPCo FAS 158 Contra Assets										
9		Net FAS 158 Contra Assets to be removed from working capital										

[1] The Turk Labor and SWEPCo Labor amounts through October 2018 were determined following the same process as calculating FERC Form 1, pages 354 and 355.

Purpose: To include prepaid pension in working capital excluding the Turk portion.

Supporting Schedules:
[a] E-17B
[b] WP B 4-7

Recap Schedules:
B-4

Southwestern Electric Power Company **WP B 4-3**
Remove FAS 158 Prepayment Contra Assets
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	(1) Account	(2) Description	(13) Projected Oct	(14) Projected Nov	(15) Projected Dec	(16) 13-Month Average
1	1650014	FAS 158 Qual Contra Asset	(90,896,301)	(90,896,301)	(90,896,301)	(92,344,882)
2	1650037	FAS158 Contra-PRW Exclud Med-D	(27,734,881)	(27,734,881)	(27,734,881)	(26,440,150)
3		Total				(118,785,032)
4		**Reduce adjustment by amount relat**				
5		[1] Total Turk Labor				
6		[1] Total SWEPCo Labor				
7		Turk portion of SWEPCo labor				
8		Amount of Turk's portion of SWEPC				(7,590,434)
9		Net FAS 158 Contra Assets to be re				(111,194,598)

[1] The Turk Labor and SWEPCo Labor

Purpose: To include prepaid pensio

Supporting Schedules:
[a] E-17B
[b] WP B 4-7

Southwestern Electric Power Company **WP B 4-4**
Calculation of Turk Payroll Ratio
Test Year Ending December 31, 2018
Docket No. 19-008-U
Actual payroll data through October 31, 2018

SWEPCo Turk Plant Payroll

Turk Payroll Ratio 6.3901%

					Benefiting Location			
Account	1128	1281	1419	1522	1642	1649	168	Amount
1070001	276			554	10,577	79,010	######	205,649
1080005					6,372	15,251		21,623
1520000						1,454,264		1,454,264
1630159						200,277		200,277
5000000					1,651	641,644		643,295
5010000					1,208	2,152		3,360
5020000						1,618,452		1,618,452
5020001						2,812		2,812
5020008						3,669		3,669
5020013						1,180		1,180
5050000						6,689		6,689
5060000					57	116,237	4,974	121,268
5100000	463	475	463		69,487	922,965		993,853
5110000						253,236		253,236
5120000					129,828	1,239,535		1,369,363
5130000					141	318,205		318,346
5140000					463	659,028		659,491
9260014							8,447	8,447
Grand Total	739	475	463	554	219,783	7,534,605	######	7,885,273

Purpose: Calculate Turk Payroll ratio for allocation of labor related items.

Total SWEPCo Payroll

Account	Amount	Account	Amount	Account	Amount
1070001	24,706,759	5020014	5,900.96	9010000	446,856.91
1080000	0	5020025	72,205	9020000	151,369.42
1080005	3,697,911	5050000	6,913,953	9020002	1,205,506.73
1510017	348,159	5060000	3,063,626	9020004	2,949.63
1520000	4,219,383	5100000	3,667,861	9030000	320,480.39
1630001	128	5110000	1,017,447	9030001	645,216.33
1630004	1,808,442	5120000	6,968,950	9030004	(8.01)
1630031	134	5130000	2,012,084	9030006	1,017,786.77
1630032	25,282	5140000	1,611,725	9030007	39,240.19
1630033	426	5240000	141	9030009	318,510.45
1630045	69	5480000	168,887	9040007	1,100.00
1630053	70,297	5530001	277,825	9070000	434,727.02
1630054	347	5570000	15,168	9070001	493,935.74
1630055	207,496	5600000	1,626,316	9080000	1,455,039.49
1630056	104,158	5612000	295	9080009	347,012.28
1630057	63,104	5620001	234,359	9200000	3,636,181.29
1630058	88	5630000	84,012	9210001	11,039.07
1630059	196,749	5660000	131,258	9220000	(54.58)
1630060	72,506	5680000	24,967	9250002	177,598.92
1630061	236,690	5690000	9,457	9260006	139.31
1630157	6,295	5700000	916,208	9260014	87,214.02
1630159	200,277	5710000	404,613	9260036	10,165.42
1830000	(19,931)	5730000	89	9280002	2,657.31
1840001	310	5800000	594,057	9302000	38.62
1840019	164	5810000	13,132	9302007	70,132.34
1840029	1,927,107	5820000	230,402	9350001	97,917.99
1840030	3	5830000	1,771,382	9350002	777.05
1840033	1,232,973	5840000	934,895	9350013	1,287,813.56
1840034	375,827	5850000	33,059	Total	############
1850000	155,971	5860000	2,940,399		
1860007	2,290,913	5870000	310,746		
4010001	6,540	5880000	8,432,784		
4264000	154,690	5890001	85		
4264001	59,758	5900000	196,539		
4560012	(54,646)	5910000	4,822		
5000000	3,752,154	5920000	401,242		
5010000	8,883	5930000	10,360,861		
5020000	8,557,925	5940000	276,742		
5020001	29,566	5950000	187,995		
5020008	7,561	5960000	266,635		
5020013	1,276	5970000	331,130		
		5980000	171,726		

Note: Voluminous payroll transactional data supporting amounts included on this workpaper of approximately 800,000 lines of data is available upon request.

Southwestern Electric Power Company **WP B 4-5**
Cost of Oxbow Investment
Test Year Ending December 31, 2018
Docket No. 19-008-U

13 month average in account 1231101(a)	24,759,407	
Cost investment of Oxbow	17,461,329	(1)
Adjustment to working capital	7,298,078	(A)

(1) Obtained from the Company's monthly account reconciliations.

Purpose: To include Oxbow cost investment in working capital.

Supporting Schedules and Workpapers:		Recap Schedules:
(a) B-5	(A)	B-4

Southwestern Electric Power Company **WP B 4-6**
Oxbow Investment Reconciliation
Test Year Ending December 31, 2018
Docket No. 19-008-U

ACCOUNT RECONCILIATION

(Cumulative Activity with no target balance) **Period Ending:** **Oct-18**

COMPANY: SOUTHWESTERN ELECTRIC POWER COMPANY
ACCOUNT: 1231101
NAME: INVEST NONCONSOL SUBS-EQUITY

EXPECTED BALANCE: 24,759,406.87

SEC Mapping: Investment in Projects

Purpose:

This account contains the cost of investments in subsidiary companies and any equity in undistributed earnings or losses. The Arklahoma Corp is a transmission line investment.

Company/BU		Consists of:			
BU 194	1	**Investment in Arklahoma**			
			Beginning Balance as of Jan. 2018- Arklahoma	171,331.29	
		January-18	Arklahoma - 2017 Net Income (Loss) for Arklahoma, SWEPCO portion is 20.50%		
					171,331.29
BU 159	2	**Investment in Southwest Arkansas Utility Corp**			
			Beginning Balance as of Jan. 2018 - SW Arkansas Utility	10,000.00	
					10,000.00
BU168	3	**Investment in Oxbow**			
			Beginning Balance as of Jan. 2018- Oxbow	17,461,328.97 (A)	
					17,461,328.97
BU168	4	**Investment in Dolet Hills Lignite Mining**			
			Beginning Balance as of Jan. 2018	7,116,746.61	
					7,116,746.61
			Ending G/L Balance		**24,759,406.87**
			Balance Check		(0)

Purpose: To include Oxbow cost investment in working capital.

Supporting Schedules and Workpapers:

Recap Schedules:
(A) WP B 4-5

Southwestern Electric Power Company **WP B 4-7**
Reconciliation of Coal and Lignite Balances
Test Year Ending December 31, 2018
Docket No. 19-008-U

Reconciliation of Coal and Lignite Monthly Balances in total to Schedule B-5

				1510001	1510016	1510018	1510020	1520000			1510017		
	coal (wp b4-2)	lignite(wp b4-2)	total (wp b4-2)	coal (b-5)	inv adj (b-5)	survey adj	fuel intransit	b/f undistr	total coal	coal diff (wp to b5)	lignite (b-5)	lignite diff (wp to b5)	total (b-5)
12/17	37,504,947	40,220,773	77,725,721	34,666,067	18,662	(886,901)	552,606	1,502,762	35,853,196	1,651,752	41,872,525	(1,651,752)	77,725,721
Jan 2018	37,660,901	36,224,671	73,885,572	33,988,571	12,605	(40,626)	3,169,109	1,467,233	38,596,892	(935,991)	35,288,680	935,991	73,885,572
Feb 2018	46,083,456	29,926,231	76,009,688	42,529,260	8,541	(131,175)	2,690,189	1,620,283	46,717,097	(633,640)	29,292,591	633,640	76,009,688
Mar 2018	49,705,914	29,191,862	78,897,776	45,594,974	24,088	(221,725)	2,783,645	1,892,781	50,073,762	(367,848)	28,824,014	367,848	78,897,776
Apr 2018	44,827,703	30,646,068	75,473,770	42,225,809	4,779	-	942,096	2,184,330	45,357,014	(529,311)	30,116,757	529,311	75,473,770
May 2018	48,394,541	30,994,493	79,389,034	45,280,782	9,916	(1,535,489)	2,760,812	2,473,646	48,989,668	(595,126)	30,399,367	595,126	79,389,034
Jun 2018	48,802,278	30,188,733	78,991,011	42,362,944	16,637	(1,228,391)	5,821,533	2,169,304	49,142,027	(339,748)	29,848,984	339,748	78,991,011
Jul 2018	50,603,869	28,238,249	78,842,118	45,924,599	12,466	(921,294)	3,933,566	2,167,938	51,117,275	(513,407)	27,724,843	513,407	78,842,118
Aug 2018	53,099,523	27,134,061	80,233,584	46,758,028	12,692	(938,013)	4,004,952	2,167,938	52,005,597	1,093,926	28,227,987	(1,093,926)	80,233,584
Sep 2018	52,337,627	23,375,956	75,713,583	44,050,739	11,957	(883,702)	3,773,065	2,167,938	49,119,997	3,217,630	26,593,586	(3,217,630)	75,713,583
Oct 2018	47,520,131	27,226,455	74,746,586	43,471,548	11,800	(872,083)	3,723,456	2,167,938	48,502,659	(982,528)	26,243,927	982,528	74,746,586
Nov 2018	40,913,001	32,330,583	73,243,584	42,571,313	11,556	(854,023)	3,646,348	2,167,938	47,543,132	(6,630,131)	25,700,452	6,630,131	73,243,584
Dec 2018	41,212,992	36,002,594	77,215,586	44,950,375	12,202	(901,750)	3,850,121	2,167,938	50,078,886	(8,865,894)	27,136,700	8,865,894	77,215,586
total	598,666,885	401,700,729	1,000,367,614	554,375,009	167,901	(9,415,172)	41,651,498	26,317,966	613,097,201	(14,430,317)	387,270,413	14,430,317	1,000,367,614
13 mo avg	46,051,299	30,900,056	76,951,355	42,644,231.43	12,915	(724,244)	3,203,961	2,024,459	47,161,323	(1,110,024)	29,790,032	1,110,024	76,951,355

Purpose: To show that the coal and lignite costs provided on WP B 4-2 is inclusive of the accounts included on Schedule B-5.

<u>Supporting Schedules</u> <u>Recap</u>
B-5 B-4

Southwestern Electric Power Company
Average Working Capital Asset Account Balances
Test Year Ending December 31, 2018
Docket No. 19-008-U

Schedule B-5

Explanation: Schedule showing balances for all assets other than plant accounts by subaccount for the 13 months ending with the last month of the test year. Subaccount Descriptions should provide a detailed discussion of the purposes of the subaccount, using examples if needed.

Line No	Account	Description	Balance 12/31/17(a)	Balance 1/31/18(a)	Balance 2/28/18(a)	Balance 3/31/18(a)	Balance 4/30/18(a)
1	1010006	Dolet Hills FAS 143 ARO Asset	16,208,616.91	16,208,616.91	16,208,616.91	16,209,810.21	16,209,807.52
2	1011001	Capital Leases	46,795,157.94	46,519,232.72	46,630,626.49	46,795,922.23	48,188,293.22
3	1011012	Accrued Capital Leases	62,863.73	124,415.79	141,803.30	1,379,274.11	466,558.51
4	1011006	Prov-Leased Assets	(20,022,232.13)	(20,062,009.89)	(20,239,962.92)	(20,585,336.36)	(20,927,957.66)
5	1080012	Dolet Hills FAS 143 ARO Deprec	(6,380,547.77)	(6,423,465.08)	(6,466,382.36)	(6,509,299.73)	(6,552,217.08)
6	1080013	ARO Removal Deprec - Accretion	6,355,203.37	6,414,650.84	6,474,323.74	6,534,132.36	6,594,101.22
7	1160007	OthElecPltAdjTurkImprmnt-EPIS	(58,411,747.11)	(58,411,747.11)	(58,411,747.11)	(58,411,747.11)	(58,411,747.11)
8	1160008	TurkAFUDCReverseTXCap-EPIS	(1,313,076.50)	(1,313,076.50)	(1,313,076.50)	(1,313,076.50)	(1,313,076.50)
9	1160009	AmortTurkImprmnt&AFUDCReversal	5,460,950.36	5,551,390.15	5,641,829.94	5,732,269.73	5,822,709.52
10	1160012	Turk Imprmnt-AuxBoiler	(18,500,000.00)	(18,500,000.00)	(18,500,000.00)	(18,500,000.00)	(18,500,000.00)
11	1160013	Turk Imprmnt-AuxBoiler Amort	1,760,696.00	1,792,146.00	1,823,596.00	1,855,046.00	1,886,496.00
12	1160016	TX Trans Veg Mgmt Cost Wrteoff	(1,194,842.07)	(1,236,964.30)	(1,242,439.67)	(1,267,135.29)	(1,326,055.84)
13	1160017	TX Distr Veg Mgmt Cost Wrteoff	(4,127,853.33)	(4,103,577.10)	(4,103,577.10)	(4,103,577.10)	(4,103,577.10)
14	1160018	TX Dist Veg Mgt WriteOff Amort	246,068.51	255,209.54	264,404.97	273,600.40	282,795.83
15	1160019	TX Tran Veg Mgt WriteOff Amort	46,766.11	48,650.60	50,497.69	52,381.50	54,352.90
16	1160020	TX Trans Costs - SERP	(510,536.06)	(159,251.17)	(159,248.12)	(159,418.38)	(159,475.73)
17	1160021	TX Distr Costs - SERP	(231,793.77)	(47,623.17)	(47,627.73)	(47,701.25)	(47,726.26)
18	1160022	TX Gen Costs - SERP	(5,901,516.59)	(303,139.04)	(302,754.79)	(302,506.81)	(302,144.64)
19	1160023	TX CWIP FinBased Incen - Trans	-	(1,613,516.76)	(1,632,905.51)	(1,652,240.34)	(1,675,118.41)
20	1160024	TX CWIP FinBased Incen - Distr	-	(2,004,879.78)	(2,020,409.09)	(2,033,856.93)	(2,054,354.53)
21	1160025	TX CWIP FinBased Incen - Gen	-	(2,387,108.55)	(2,410,257.31)	(2,419,603.46)	(2,432,079.20)
22	1160026	TX RWIP FinBased Incen - Trans	-	(62,412.96)	(62,905.96)	(63,094.97)	(63,276.17)
23	1160027	TX RWIP FinBased Incen - Distr	-	(79,404.55)	(80,309.06)	(80,859.80)	(82,389.57)
24	1160028	TX RWIP FinBased Incen - Gen	-	(93,023.90)	(93,160.23)	(93,506.64)	(93,921.63)
25	1230000	Invest Nonconsol Assoc Co	-	-	-	-	-
26	1231003	Capital Contributions to Subs	100,000.00	100,000.00	100,000.00	100,000.00	100,000.00
27	1231005	Invest in Subs Retained Erngs	1,873,774.39	1,874,852.87	1,877,021.03	1,879,767.80	1,882,977.60
28	1231101	Invest Nonconsol Subs-Equity	24,759,406.87	24,759,406.87	24,759,406.87	24,759,406.87	24,759,406.87
29	1231102	Equity in Erngs Nonconsol Subs	12,324,476.97	12,537,913.90	12,708,700.88	12,856,651.75	13,006,661.45
30	1240002	Oth Investments-Nonassociated	878,008.64	878,008.64	878,008.64	878,008.64	878,008.64
31	1240027	Other Property - RWIP	-	-	-	129.11	1,251.23
32	1240029	Other Property - CPR	301,443.53	301,443.53	301,443.53	301,443.53	301,443.53
33	1290001	Non-UMWA PRW Funded Position	30,137,864.41	30,137,864.41	30,137,864.41	28,996,881.16	28,996,881.16
34	1290002	SFAS 106 - Non-UMWA PRW	-	603,943.59	1,207,887.18	1,815,174.00	2,391,866.58
35	1310000	Cash	1,642,739.42	1,856,638.21	2,332,530.19	719,646.45	2,042,467.92
36	1340018	Spec Deposits - Elect Trading	100,252.23	100,303.24	100,097.06	100,148.07	100,049.38
37	1340046	Deposits-O&M Dolet Hills Plant	2,807,000.00	5,087,000.00	10,195,000.00	6,774,380.58	6,774,380.58
38	1340048	Spec Deposits-Trading Contra	-	-	570,348.00	46,320.00	13,293.00
39	1340050	Spec Deposit Mizuho Securities	-	-	-	-	-
40	1340051	Spec Depost RBC	22,782.86	46,907.85	-	-	37,627.95

Supporting Schedules:
(a) E-17B

Recap Schedules:
(A)Schedule B-4

Southwestern Electric Power Company
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Docket No. 19-008-U

Schedule B-5

Explanation: Schedule showing balances for all assets other than plant accounts by subaccount for the 13 months ending with the last month of the test year. Subaccount Descriptions should provide a detailed discussion of the purposes of the subaccount, using examples if needed.

Line No	Account	Description	Balance 12/31/17(a)	Balance 1/31/18(a)	Balance 2/28/18(a)	Balance 3/31/18(a)	Balance 4/30/18(a)
41	1340053	Deposits - Flexible Spending	90,164.07	90,164.07	90,164.07	90,164.07	90,164.07
42	1420001	Customer A/R - Electric	93,936,702.43	110,597,053.18	109,408,163.17	93,996,288.11	92,063,041.30
43	1420006	A/R-Customer Assistance	-	1,089.00	557.00	-	-
44	1420014	Customer A/R-System Sales	17,158,587.51	17,488,404.59	12,887,925.39	14,309,717.91	17,302,742.70
45	1420022	Cust A/R - Factored	(94,050,316.69)	(117,710,690.72)	(107,684,048.83)	(90,606,597.03)	(84,558,948.08)
46	1420023	Cust A/R-System Sales - MLR	-	-	-	-	-
47	1420044	Customer A/R - Estimated	33,572,378.78	37,292,697.65	37,121,089.28	34,004,943.50	31,135,456.25
48	1420048	Emission Allowance Trading	700.00	-	-	-	-
49	1420051	MISO AR Accrual	-	-	-	325,676.87	-
50	1420055	SPP AR Accrual	7,263,317.52	8,385,754.45	5,062,063.84	9,079,188.25	1,998,867.46
51	1420101	Other Accounts Rec - Cust	271,979.14	338,099.00	342,318.02	547,515.07	258,314.03
52	1420102	AR Peoplesoft Billing - Cust	11,079,730.54	11,526,316.23	7,036,218.46	3,847,805.93	3,092,280.88
53	1430002	Allowances	24.07	24.07	24.07	24.07	24.07
54	1430022	2001 Employee Biweekly Pay Cnv	7,628.97	7,628.97	7,628.97	7,628.97	7,628.97
55	1430080	Jointly Owned Unit O&M Billing	22,896,433.91	19,124,560.55	18,283,976.34	9,885,846.97	10,078,702.58
56	1430081	Damage Recovery - Third Party	70,264.49	103,333.49	70,004.04	78,947.04	26,115.00
57	1430083	Damage Recovery Offset Demand	(70,264.49)	(111,446.49)	(82,646.04)	(78,947.04)	(31,926.00)
58	1430086	AR Accrual NYMEX OTC Penults	0.00	0.00	0.00	0.00	0.00
59	1430101	Other Accounts Rec - Misc	1,410,840.26	1,512,171.63	1,394,085.35	1,201,952.43	1,692,052.59
60	1430102	AR Peoplesoft Billing - Misc	1,099,426.13	2,732,625.13	1,963,839.47	957,943.87	2,938,763.26
61	1430103	AR Long-Term-Miscellaneous	1,386,715.49	1,317,379.72	1,248,043.95	1,178,708.18	1,109,372.41
62	1440002	Uncoll Accts-Other Receivables	(1,329,448.12)	(1,235,045.75)	(793,580.98)	(557,714.93)	(557,714.93)
63	1450000	Corp Borrow Prg (NR-Assoc)	-	287,581,426.00	230,675,815.89	-	-
64	1460001	A/R Assoc Co - InterUnit G/L	19,785,079.10	20,937,166.50	37,512,609.40	12,771,236.51	12,129,654.01
65	1460004	A/R Assoc Co - CM Bills	90,718.31	23,274.90	31,735.81	105,027.76	79,899.23
66	1460006	A/R Assoc Co - Intercompany	239,972.83	207,098.25	245,509.70	369,406.43	142,364.31
67	1460009	A/R Assoc Co - InterUnit A/P	10,033.31	8,064.32	756.11	0.00	1,506.41
68	1460011	A/R Assoc Co - Multi Pmts	7,323,850.93	7,214,830.04	6,742,711.98	2,167,042.41	2,315,088.69
69	1460025	Fleet - M4 - A/R	20,176.90	19,848.31	20,469.52	(0.00)	59,484.70
70	1510001	Fuel Stock - Coal	34,666,066.76	33,988,571.25	42,529,259.71	45,594,973.80	42,225,808.79
71	1510002	Fuel Stock - Oil	4,351,690.98	4,274,571.78	4,056,312.94	3,806,642.50	3,725,072.78
72	1510016	Coal Inv on Hand Transp	18,661.59	12,605.24	8,540.83	24,087.86	4,778.91
73	1510017	Lignite Inv on Hand Inc Transp	41,872,525.19	35,288,679.66	29,292,590.95	28,824,014.46	30,116,756.94
74	1510018	Coal Survey Adjustment	(886,900.91)	(40,625.60)	(131,175.43)	(221,725.25)	-
75	1510020	Fuel Stock Coal - Intransit	552,606.13	3,169,108.93	2,690,188.71	2,783,644.70	942,095.77
76	1520000	Fuel Stock Exp Undistributed	1,502,762.16	1,467,232.58	1,620,283.02	1,892,780.89	2,184,330.09
77	1540001	M&S - Regular	65,997,476.67	65,662,848.96	65,769,789.60	66,012,510.76	65,754,003.71
78	1540004	M&S - Exempt Material	573,204.33	577,703.19	589,867.84	562,782.49	559,748.53
79	1540006	M&S - Lime and Limestone	708,002.06	959,849.05	1,965,266.61	1,667,960.42	1,470,547.24
80	1540013	Transportation Inventory	62,747.80	62,747.80	62,747.80	62,747.80	87,065.69

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(a) E-17B

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Schedule B-5

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Line No	Account	Description	Balance 12/31/17(a)	Balance 1/31/18(a)	Balance 2/28/18(a)	Balance 3/31/18(a)	Balance 4/30/18(a)
81	1540025	Matls Supply-Activated Carbon	413,621.60	470,343.52	387,157.17	261,470.11	329,289.92
82	1540028	M&S - Anhydrous Ammonia	13,042.02	31,690.80	17,840.26	28,753.29	2,765.61
83	1540030	Matls Supply-Calcium Bromide	54,838.83	65,857.03	58,863.25	52,355.65	51,237.16
84	1581012	CSAPR An. NOx Inv. - Current	1,918.74	-	-	-	-
85	1581014	CSAPR Seas NOx Comp Inv - Curr	88,089.16	88,089.16	88,402.63	126,502.63	126,502.63
86	1630004	Strs Exp-T&D Satellite Storerm	-	-	-	-	-
87	1630056	Knox Lee Power Plant	-	-	-	-	-
88	1630059	Pirkey Power Plant	-	-	-	-	-
89	1630061	Welsh Power Plant	-	-	-	-	-
90	1650001	Prepaid Insurance	1,377,548.65	1,158,305.16	939,061.67	735,862.58	516,882.60
91	165000218	Prepaid Taxes	-	899,065.88	449,532.94	-	998,958.50
92	1650005	Prepaid Employee Benefits	-	43,126.14	43,950.50	-	-
93	1650006	Other Prepayments	16,474,492.30	16,806,557.02	17,512,052.84	16,349,332.78	17,307,667.91
94	1650009	Prepaid Carry Cost-Factored AR	129,132.50	237,046.16	167,813.48	128,606.80	172,566.72
95	1650010	Prepaid Pension Benefits	95,630,493.29	94,919,108.29	94,207,723.29	93,601,553.79	92,925,240.63
96	165000218	Prepaid Taxes	-	-	-	-	-
97	165001116	Prepaid Sales Taxes	-	-	-	-	-
98	165001117	Prepaid Sales Taxes	803,600.00	-	(1,800,069.60)	-	-
99	165001118	Prepaid Sales Taxes	-	875,000.00	3,445,504.40	720,400.00	737,200.00
100	165001216	Prepaid Use Taxes	-	-	-	-	-
101	165001217	Prepaid Use Taxes	20,086.86	-	-	-	-
102	165001218	Prepaid Use Taxes	-	21,847.66	1,643.33	1,261.02	8,325.32
103	165001316	Prepaid Local Franchise Taxes	-	-	-	-	-
104	165001317	Prepaid Local Franchise Taxes	57,864.77	-	-	-	-
105	165001318	Prepaid Local Franchise Taxes	-	57,118.97	56,563.67	56,085.32	55,606.29
106	1650014	FAS 158 Qual Contra Asset	(95,630,493.29)	(94,919,108.29)	(94,207,723.29)	(93,601,553.79)	(92,925,240.63)
107	1650016	FAS 112 ASSETS	-	-	-	-	-
108	1650017	Prepayment - Coal	9,075,000.00	10,188,116.99	7,047,221.71	4,303,349.94	3,344,003.52
109	1650018	Affl Trans Intercon Providers	(0.00)	0.00	0.00	0.00	0.00
110	1650021	Prepaid Insurance - EIS	980,733.55	930,559.73	653,146.01	1,819,034.34	1,534,360.37
111	1650023	Prepaid Lease	199,883.68	185,583.68	171,283.68	192,983.68	178,683.68
112	1650029	Future Wetlands Credits L-T	300,000.00	300,000.00	300,000.00	300,000.00	300,000.00
113	1650030	Other Prepayments - Long Term	-	618,643.39	618,643.39	618,643.39	1,709,806.12
114	1650035	PRW Without MED-D Benefits	23,527,840.41	24,131,784.00	24,735,727.59	25,343,014.41	25,919,706.99
115	1650037	FAS158 Contra-PRW Exclud Med-D	(23,527,840.41)	(24,131,784.00)	(24,735,727.59)	(25,343,014.41)	(25,919,706.99)
116	1710010	Interest Under Recover - LA	-	-	-	-	-
117	1710048	Interest Receivable -FIT -LT	1,691.00	1,691.00	1,691.00	1,918.00	1,918.00
118	1710348	Interest Receivable -SIT -LT	-	-	-	-	-
119	1720000	Rents Receivable	1,592,143.41	743,125.65	895,440.19	443,401.12	595,140.32
120	1730003	Acrd Utility Rev-West	35,186,615.49	32,163,348.63	26,468,804.84	24,599,040.53	27,466,258.83

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Schedule B-5

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Line No	Account	Description	Balance 12/31/17(a)	Balance 1/31/18(a)	Balance 2/28/18(a)	Balance 3/31/18(a)	Balance 4/30/18(a)
121	1740000	Misc Current & Accrued Assets	-	-	-	81,201.55	-
122	1750001	Curr. Unreal Gains - NonAffil	6,395,724.77	5,221,774.72	4,803,350.05	1,761,863.34	1,735,412.42
123	1750002	Long-Term Unreal Gns - Non Aff	-	-	-	-	15,301.00
124	1750021	S/T Asset MTM Collateral	-	-	(570,348.00)	(46,320.00)	(12,188.00)
125	1750022	L/T Asset MTM Collateral	-	-	-	-	(1,105.00)
126	1810002	Unamort Debt Exp - Inst Pur Cn	65,883.44	50,453.98	35,024.52	32,219.87	29,415.22
127	1810003	Unamort Debt Exp Notes Payable	288,376.69	278,748.40	269,120.11	259,491.82	249,863.53
128	1810006	Unamort Debt Exp - Sr Unsec Nt	10,018,988.77	14,203,859.77	14,087,480.70	14,079,393.55	13,991,101.99
129	1810102	Unamort Debt Exp-PCB Ins	25,944.54	12,623.38	-	-	-
130	1823000	Other Regulatory Assets	181,703.00	155,614.00	131,428.00	123,552.00	112,004.00
131	1823010	Energy Efficiency Recovery	4,089,562.58	3,383,451.59	2,955,349.52	3,107,405.82	3,489,930.01
132	1823075	Def Exp Selling Price Variance	-	-	-	730,747.76	1,071,000.31
133	1823077	Unreal Loss on Fwd Commitments	-	-	-	304,954.74	2,786,685.73
134	1823099	Asset Retirement Obligations	4,489,390.29	4,600,449.88	4,711,784.30	4,823,332.20	4,935,092.17
135	1823108	Reg Asset - Rate Case Expenses	7,016,941.94	6,745,258.33	6,513,744.31	6,421,877.32	6,241,475.03
136	1823149	Unrecovered Fuel Cost - LA	-	1,236,086.89	3,846,787.16	812,928.13	4,349.00
137	1823150	Unrecovered Fuel Cost - AR	14,065,695.06	16,224,648.88	16,069,765.20	15,649,771.88	15,411,250.16
138	1823165	REG ASSET FAS 158 QUAL PLAN	96,290,886.00	96,290,886.00	96,290,886.00	95,038,202.25	95,038,202.25
139	1823166	REG ASSET FAS 158 OPEB PLAN	(3,753,348.25)	(3,753,348.25)	(3,753,348.25)	(3,047,164.52)	(3,047,164.52)
140	1823167	REG Asset FAS 158 SERP Plan	1,129,980.00	1,129,980.00	1,129,980.00	1,115,587.25	1,115,587.25
141	1823180	Deferred Storm Expense	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
142	1823219	Under Recovered EAC - LA	246,993.50	69,853.46	98,983.66	145,198.38	-
143	1823241	Valley District Due Diligence	33,032.03	16,516.02	-	-	-
144	1823299	SFAS 106 Medicare Subsidy	3,733,168.39	3,688,725.89	3,644,283.39	3,599,840.89	3,555,398.39
145	1823301	SFAS 109 Flow Thru Defd FIT	69,608,874.18	69,594,089.02	69,673,769.73	69,782,112.98	69,752,946.93
146	1823302	SFAS 109 Flow Thru Defrd SIT	189,260,844.00	189,243,085.00	189,238,001.00	191,055,315.00	191,317,110.00
147	1823306	Net CCS FEED Study Costs	470,074.53	458,467.58	446,858.73	446,858.73	446,858.73
148	1823324	LA FRP Asset	175,112.05	167,261.40	159,410.75	151,560.10	143,709.45
149	1823348	Louisiana Vegetation Managemnt	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
150	1823359	SWEPCo Transmission Recovery	3,264,402.55	3,264,402.55	3,264,402.55	3,264,402.55	3,264,402.55
151	1823360	2010 Severance Costs	269,940.70	134,970.21	-	-	-
152	1823374	Environmental Chemical Cost-AR	2,122,776.57	2,213,140.47	2,294,870.19	2,371,933.83	2,387,724.06
153	1823377	NBV - AROs Retired Plants	508,193.73	507,600.39	507,007.05	506,413.71	505,820.37
154	1823424	LA 2015 FRP Asset-SPP Deferral	4,720,151.85	4,720,151.85	4,886,832.56	4,928,512.15	4,970,191.74
155	1823425	LA 2015 FRP Asset - Contra	(102,864.75)	(102,864.75)	(180,745.40)	(200,219.96)	(219,694.52)
156	1823428	Welsh 2 TX Portion Undepr Bal	17,576,705.35	17,536,407.13	17,496,013.58	17,455,524.47	17,414,939.57
157	1823539	Facilities Maint SWEPCO LA	551,611.17	551,548.81	571,358.13	586,813.51	603,637.26
158	1823554	WELSH/FLINT CREEK ENVIRONM DEF	23,555,541.08	23,418,590.26	23,281,639.44	23,144,688.62	23,007,737.80
159	1823555	WELSH/FLINTCREEK ENVIR-CONTRA	(8,239,061.85)	(8,191,160.33)	(8,143,258.81)	(8,095,357.29)	(8,047,455.77)
160	1830000	Prelimin Surv&Investgtn Chrgs	1,149,702.59	1,181,848.49	1,178,367.68	1,179,446.06	1,209,300.66

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161	1840002	Accounts Pay Adj - Clearing	-	-	-	-	-
162	1840019	CMS & CMF - Clearing Activity	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
163	1840033	Alliance Rail Car - OH	103,523.77	132,154.43	(187,013.33)	258,827.07	(62,165.59)
164	1840035	IT Oper Company (OPCO) Clearng	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
165	1860001	Allowances	123.29	2,042.03	2,042.03	2,142.03	2,042.03
166	1860002	Deferred Expenses	(260,877.17)	(227,699.51)	(210,195.39)	691.88	(152,232.08)
167	186000316	Deferred Property Taxes	-	-	-	-	-
168	186000318	Deferred Property Taxes	-	59,504,749.00	54,095,226.00	48,685,703.00	43,276,180.00
169	1860005	Unidentified Cash Receipts	-	(1,285.83)	(1,285.83)	-	(486.50)
170	1860007	Billings and Deferred Projects	2,364,290.08	3,240,180.40	3,857,528.73	4,916,779.07	5,069,491.91
171	1860015	Billings Paid Union Benefits	-	1,374.64	6,570.01	-	2,315.56
172	1860046	Railroad Cars Subleased	-	12,566.00	15,124.00	-	6,787.59
173	1860077	Agency Fees - Factored A/R	2,764,073.96	3,213,679.61	2,956,074.18	2,612,012.13	2,647,032.77
174	186008118	Defd Property Tax - Cap Lease	-	158,583.00	144,166.00	129,749.00	115,332.00
175	1860089	Reclamation Advance	17,118,863.07	16,828,424.49	16,588,926.54	16,304,767.57	15,546,351.19
176	1860150	Deferred Rate Case Expense	97,947.89	75,914.74	81,368.89	73,314.89	103,776.89
177	1860153	Unamortized Credit Line Fees	497,232.71	468,035.78	453,982.43	455,565.21	441,110.94
178	1860154	Affl Deferred Tran(IPP) Credit	-	-	-	-	-
179	1860156	Sabine Mine Rusk Preparation	13,793,764.47	13,761,572.85	13,724,956.33	13,670,412.54	13,654,342.13
180	1860160	Deferred Expenses - Current	109,552.93	515,369.25	151,223.91	141,394.99	145,762.88
181	1860166	Def Lease Assets - Non Taxable	235,312.86	235,312.86	-	168,101.24	168,101.24
182	1860171	Marshall South Mine Prep	17,311.28	14,514.26	12,274.74	10,239.58	(1,112.22)
183	1860185	Long Term Assoc AR	-	-	-	-	-
184	1890001	Loss Recqd Debt - FMB	2,350,792.63	2,333,584.18	2,316,375.73	2,299,167.28	2,281,958.83
185	1890002	Loss Rec Debt-Ins Purch Cont	228,387.51	203,627.93	178,867.95	174,779.39	170,690.83
186	1890004	Loss Rec Debt-Debentures	2,081,452.20	2,061,795.23	2,042,138.26	2,022,481.29	2,002,824.32
187	1900011	ADIT Federal Non-UMWA PRW OCI	(599,901.90)	(599,901.90)	(599,901.90)	(508,594.00)	(508,594.00)
188	1900015	ADIT-Fed-Hdg-CF-Int Rate	1,897,348.58	1,832,812.85	1,819,905.72	1,781,185.79	1,742,464.37
189	1901001	Accum Deferred FIT - Other	95,841,180.32	57,980,022.64	58,150,159.72	56,661,849.32	57,590,452.85
190	1901002	Accum Deferred SIT - Other	47,528,631.06	47,528,631.06	47,528,631.06	48,923,746.89	48,923,746.89
191	1902001	Accum Defd FIT - Oth Inc & Ded	1,619,184.81	1,484,154.82	1,349,124.82	1,214,094.82	1,079,064.82
192	1903001	Acc Dfd FIT - FAS109 Flow Thru	41,465,204.02	41,429,701.85	41,396,861.54	41,746,724.73	41,769,928.91
193	1904001	Accum Dfd FIT - FAS 109 Excess	150,046,272.11	150,035,737.78	150,024,573.21	149,344,500.99	149,110,367.20
		Total	1,202,254,364.59	1,513,636,407.73	1,463,717,400.47	1,178,610,386.17	1,175,231,004.53

Subaccount Descriptions:
Refer to Schedule E-9

Supporting Schedules:
(a) E-17B

Recap Schedules:
(A)Schedule B-4

Southwestern Electric Power Company
Average Working Capital Asset Account Balances
Test Year Ending December 31, 2018
Docket No. 19-008-U

Schedule B-5

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Line No	Account	Description	Balance 5/31/18(a)	Balance 6/30/18(a)	Balance 7/31/18(a)	Balance 8/31/18(a)	Balance 9/30/18(a)
1	1010006	Dolet Hills FAS 143 ARO Asset	16,208,616.91	41,520,820.72	41,520,820.72	41,520,820.72	41,520,820.72
2	1011001	Capital Leases	48,735,660.43	48,251,594.81	47,912,412.58	47,912,413.00	47,912,413.00
3	1011012	Accrued Capital Leases	160,929.74	134,773.18	124,545.96	124,546.00	124,546.00
4	1011006	Prov-Leased Assets	(21,291,117.97)	(21,111,121.52)	(21,116,832.29)	(21,116,832.00)	(21,116,832.00)
5	1080012	Dolet Hills FAS 143 ARO Deprec	(6,595,134.37)	(6,638,051.74)	(6,794,476.54)	(6,808,928.00)	(6,844,716.00)
6	1080013	ARO Removal Deprec - Accretion	6,654,207.83	6,714,363.21	6,774,365.37	6,792,416.00	6,806,360.00
7	1160007	OthElecPltAdjTurkImprmnt-EPIS	(58,411,747.11)	(58,411,747.11)	(58,411,747.11)	(58,307,470.00)	(58,203,071.00)
8	1160008	TurkAFUDCReverseTXCap-EPIS	(1,313,076.50)	(1,313,076.50)	(1,313,076.50)	(1,310,732.00)	(1,308,386.00)
9	1160009	AmortTurkImprmnt&AFUDCReversal	5,913,149.31	6,003,589.10	6,094,028.89	6,083,150.00	6,072,258.00
10	1160012	Turk Imprmnt-AuxBoiler	(18,500,000.00)	(18,500,000.00)	(18,500,000.00)	(18,466,974.00)	(18,433,909.00)
11	1160013	Turk Imprmnt-AuxBoiler Amort	1,917,946.00	1,949,396.00	1,980,846.00	1,977,310.00	1,973,769.00
12	1160016	TX Trans Veg Mgmt Cost Wrteoff	(1,364,925.45)	(1,420,452.64)	(1,441,054.14)	(1,438,482.00)	(1,435,906.00)
13	1160017	TX Distr Veg Mgmt Cost Wrteoff	(4,103,577.10)	(4,103,577.10)	(4,103,577.10)	(4,096,251.00)	(4,088,917.00)
14	1160018	TX Dist Veg Mgt WriteOff Amort	291,991.26	301,186.69	310,382.12	309,828.00	309,273.00
15	1160019	TX Tran Veg Mgt WriteOff Amort	56,382.09	58,493.83	60,636.20	60,528.00	60,420.00
16	1160020	TX Trans Costs - SERP	(159,518.51)	(159,519.76)	(159,523.31)	(159,239.00)	(158,953.00)
17	1160021	TX Distr Costs - SERP	(47,749.36)	(47,774.86)	(47,811.70)	(47,726.00)	(47,641.00)
18	1160022	TX Gen Costs - SERP	(301,778.86)	(301,357.70)	(300,961.68)	(300,424.00)	(299,886.00)
19	1160023	TX CWIP FinBased Incen - Trans	(1,692,898.21)	(1,720,206.60)	(1,747,345.47)	(1,744,226.00)	(1,741,103.00)
20	1160024	TX CWIP FinBased Incen - Distr	(2,056,392.50)	(2,074,269.22)	(2,107,031.67)	(2,103,270.00)	(2,099,504.00)
21	1160025	TX CWIP FinBased Incen - Gen	(2,440,168.53)	(2,460,164.65)	(2,468,125.88)	(2,463,720.00)	(2,459,309.00)
22	1160026	TX RWIP FinBased Incen - Trans	(63,459.68)	(63,518.80)	(63,897.38)	(63,783.00)	(63,669.00)
23	1160027	TX RWIP FinBased Incen - Distr	(81,622.73)	(81,812.21)	(84,668.54)	(84,517.00)	(84,366.00)
24	1160028	TX RWIP FinBased Incen - Gen	(93,894.73)	(93,789.74)	(94,091.98)	(93,924.00)	(93,756.00)
25	1230000	Invest Nonconsol Assoc Co	-	-	-	326,659.00	574,485.00
26	1231003	Capital Contributions to Subs	100,000.00	100,000.00	100,000.00	100,000.00	100,000.00
27	1231005	Invest in Subs Retained Erngs	1,885,951.36	1,888,850.63	1,892,064.44	1,892,064.00	1,892,064.00
28	1231101	Invest Nonconsol Subs-Equity	24,759,406.87	24,759,406.87	24,759,406.87	24,759,407.00	24,759,407.00
29	1231102	Equity in Erngs Nonconsol Subs	13,206,851.97	13,496,494.99	13,766,159.31	13,766,159.00	13,766,159.00
30	1240002	Oth Investments-Nonassociated	878,008.64	878,008.64	878,008.64	1,071,009.00	1,263,009.00
31	1240027	Other Property - RWIP	1,896.29	2,693.74	3,498.28	3,498.00	3,498.00
32	1240029	Other Property - CPR	301,443.53	301,443.53	301,443.53	301,444.00	301,444.00
33	1290001	Non-UMWA PRW Funded Position	28,996,881.16	27,855,897.91	27,855,897.91	27,855,898.00	27,855,898.00
34	1290002	SFAS 106 - Non-UMWA PRW	2,996,924.59	3,601,982.60	4,207,040.61	4,207,041.00	4,207,041.00
35	1310000	Cash	1,550,389.84	2,122,378.37	2,505,236.65	1,625,000.00	1,625,000.00
36	1340018	Spec Deposits - Elect Trading	100,132.16	100,219.81	4,560,651.71	4,560,652.00	4,560,652.00
37	1340046	Deposits-O&M Dolet Hills Plant	5,317,898.48	3,044,000.00	3,348,000.00	3,348,000.00	3,348,000.00
38	1340048	Spec Deposits-Trading Contra	95,593.00	74,181.00	49,036.00	49,036.00	49,036.00
39	1340050	Spec Deposit Mizuho Securities	-	-	-	-	-
40	1340051	Spec Depost RBC	-	-	37,410.90	37,411.00	37,411.00

Supporting Schedules:
(a) E-17B

Recap Schedules:
(A)Schedule B-4

Southwestern Electric Power Company
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Docket No. 19-008-U

Schedule B-5

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Line No	Account	Description	Balance 5/31/18(a)	Balance 6/30/18(a)	Balance 7/31/18(a)	Balance 8/31/18(a)	Balance 9/30/18(a)
41	1340053	Deposits - Flexible Spending	90,164.07	90,164.07	90,164.07	90,164.00	90,164.00
42	1420001	Customer A/R - Electric	99,140,232.68	126,730,581.45	137,139,619.19	137,139,619.00	137,139,619.00
43	1420006	A/R-Customer Assistance	-	-	-	-	-
44	1420014	Customer A/R-System Sales	18,712,331.11	14,796,181.84	15,272,819.59	15,272,820.00	15,272,820.00
45	1420022	Cust A/R - Factored	(101,267,471.62)	(129,687,510.80)	(144,670,792.20)	(144,670,792.00)	(144,670,792.00)
46	1420023	Cust A/R-System Sales - MLR	103,628.34	145,999.41	251,008.00	251,008.00	251,008.00
47	1420044	Customer A/R - Estimated	27,658,142.71	23,923,508.05	20,640,333.18	20,640,333.00	20,640,333.00
48	1420048	Emission Allowance Trading	-	-	-	-	-
49	1420051	MISO AR Accrual	-	-	-	-	-
50	1420055	SPP AR Accrual	2,477,838.79	444,314.03	(0.00)	-	-
51	1420101	Other Accounts Rec - Cust	465,362.41	571,141.95	563,032.56	563,033.00	563,033.00
52	1420102	AR Peoplesoft Billing - Cust	2,866,987.95	4,288,347.61	5,554,690.12	5,554,690.00	5,554,690.00
53	1430002	Allowances	105.72	19.80	19.80	20.00	20.00
54	1430022	2001 Employee Biweekly Pay Cnv	7,628.97	7,628.97	7,628.97	7,629.00	7,629.00
55	1430080	Jointly Owned Unit O&M Billing	10,026,213.27	17,035,662.15	18,340,069.42	18,340,069.00	18,340,069.00
56	1430081	Damage Recovery - Third Party	49,114.20	55,299.00	80,592.57	80,593.00	80,593.00
57	1430083	Damage Recovery Offset Demand	(57,267.00)	(55,299.00)	(86,478.57)	(86,479.00)	(86,479.00)
58	1430086	AR Accrual NYMEX OTC Penults	0.00	0.00	0.00	-	-
59	1430101	Other Accounts Rec - Misc	1,656,657.53	1,078,865.56	950,296.78	950,297.00	950,297.00
60	1430102	AR Peoplesoft Billing - Misc	2,326,136.59	2,277,012.58	931,407.48	931,407.00	931,407.00
61	1430103	AR Long-Term-Miscellaneous	1,040,036.64	970,700.87	901,365.10	901,365.00	901,365.00
62	1440002	Uncoll Accts-Other Receivables	(557,714.93)	(557,714.93)	(557,714.93)	(557,715.00)	(557,715.00)
63	1450000	Corp Borrow Prg (NR-Assoc)	-	-	-	-	485,089,003.00
64	1460001	A/R Assoc Co - InterUnit G/L	23,132,654.82	30,319,011.20	27,115,186.35	27,115,186.00	27,115,186.00
65	1460004	A/R Assoc Co - CM Bills	79,998.95	42,698.70	31,877.62	31,878.00	31,878.00
66	1460006	A/R Assoc Co - Intercompany	222,096.26	(1,115,090.59)	1,517,768.66	1,517,769.00	1,517,769.00
67	1460009	A/R Assoc Co - InterUnit A/P	15,736.96	27,805.13	22,947.89	22,948.00	22,948.00
68	1460011	A/R Assoc Co - Multi Pmts	6,462,191.39	5,247,622.42	10,323,653.40	10,323,653.00	10,323,653.00
69	1460025	Fleet - M4 - A/R	53,449.84	28,605.36	16,583.32	16,583.00	16,583.00
70	1510001	Fuel Stock - Coal	45,280,782.31	42,362,944.29	45,924,598.61	46,758,028.00	44,050,739.00
71	1510002	Fuel Stock - Oil	4,005,867.29	4,419,035.12	4,591,541.00	4,591,541.00	4,591,541.00
72	1510016	Coal Inv on Hand Transp	9,916.18	16,637.21	12,466.02	12,692.00	11,957.00
73	1510017	Lignite Inv on Hand Inc Transp	30,399,366.65	29,848,984.23	27,724,842.51	28,227,987.00	26,593,586.00
74	1510018	Coal Survey Adjustment	(1,535,489.15)	(1,228,391.33)	(921,293.51)	(938,013.00)	(883,702.00)
75	1510020	Fuel Stock Coal - Intransit	2,760,812.46	5,821,532.61	3,933,566.35	4,004,952.00	3,773,065.00
76	1520000	Fuel Stock Exp Undistributed	2,473,646.03	2,169,303.77	2,167,937.92	2,167,938.00	2,167,938.00
77	1540001	M&S - Regular	65,867,540.06	66,688,758.69	66,526,150.71	66,526,150.00	66,526,150.00
78	1540004	M&S - Exempt Material	509,279.02	518,534.68	516,794.04	516,794.00	516,794.00
79	1540006	M&S - Lime and Limestone	1,048,897.37	1,136,179.74	1,403,683.78	1,403,684.00	1,403,684.00
80	1540013	Transportation Inventory	87,065.69	87,065.69	87,065.69	87,066.00	87,066.00

Supporting Schedules:
(a) E-17B

Recap Schedules:
(A)Schedule B-4

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81	1540025	Matls Supply-Activated Carbon	425,338.43	441,137.51	298,572.23	298,572.00	298,572.00
82	1540028	M&S - Anhydrous Ammonia	43,828.01	31,987.49	18,579.02	18,579.00	18,579.00
83	1540030	Matls Supply-Calcium Bromide	56,524.16	59,898.64	57,670.85	57,671.00	57,671.00
84	1581012	CSAPR An. NOx Inv. - Current	-	-	-	(43,935.00)	(99,768.00)
85	1581014	CSAPR Seas NOx Comp Inv - Curr	105,009.89	110,236.86	67,068.39	87,858.00	112,608.00
86	1630004	Strs Exp-T&D Satellite Storerm	0.00	(0.00)	-	-	-
87	1630056	Knox Lee Power Plant	-	0.00	-	-	-
88	1630059	Pirkey Power Plant	(0.00)	(0.00)	-	-	-
89	1630061	Welsh Power Plant	0.01	0.01	0.01	-	-
90	1650001	Prepaid Insurance	594,525.40	524,248.59	2,063,566.74	2,063,567.00	2,063,567.00
91	165000218	Prepaid Taxes	499,479.25	-	-	-	-
92	1650005	Prepaid Employee Benefits	-	-	-	-	-
93	1650006	Other Prepayments	17,144,149.12	17,091,460.88	16,914,733.62	16,914,734.00	16,914,734.00
94	1650009	Prepaid Carry Cost-Factored AR	171,563.56	218,771.29	179,616.75	179,617.00	179,617.00
95	1650010	Prepaid Pension Benefits	92,248,927.47	91,572,614.31	90,896,301.15	90,896,301.15	90,896,301.15
96	165000218	Prepaid Taxes	-	-	1,125,105.28	1,125,105.00	1,125,105.00
97	165001116	Prepaid Sales Taxes	-	-	-	-	-
98	165001117	Prepaid Sales Taxes	-	-	-	-	-
99	165001118	Prepaid Sales Taxes	1,848,450.62	1,023,400.00	1,225,200.00	1,225,200.00	1,225,200.00
100	165001216	Prepaid Use Taxes	-	-	-	-	-
101	165001217	Prepaid Use Taxes	-	-	-	-	-
102	165001218	Prepaid Use Taxes	266.57	1,244.91	159.22	159.00	159.00
103	165001316	Prepaid Local Franchise Taxes	-	-	-	-	-
104	165001317	Prepaid Local Franchise Taxes	-	-	-	-	-
105	165001318	Prepaid Local Franchise Taxes	55,052.65	54,327.41	53,574.95	53,575.00	53,575.00
106	1650014	FAS 158 Qual Contra Asset	(92,248,927.47)	(91,572,614.31)	(90,896,301.15)	(90,896,301.15)	(90,896,301.15)
107	1650016	FAS 112 ASSETS	-	-	-	-	-
108	1650017	Prepayment - Coal	4,616,210.78	380,465.73	4,200,175.16	4,200,175.00	4,200,175.00
109	1650018	Affl Trans Intercon Providers	0.00	0.00	0.00	-	-
110	1650021	Prepaid Insurance - EIS	1,249,686.40	965,012.43	3,126,986.33	3,126,986.00	3,126,986.00
111	1650023	Prepaid Lease	212,383.68	198,083.68	183,783.68	183,784.00	183,784.00
112	1650029	Future Wetlands Credits L-T	300,000.00	300,000.00	300,000.00	300,000.00	300,000.00
113	1650030	Other Prepayments - Long Term	1,709,806.12	1,709,806.12	1,709,806.12	1,709,806.00	1,709,806.00
114	1650035	PRW Without MED-D Benefits	26,524,765.00	27,129,823.01	27,734,881.02	27,734,881.02	27,734,881.02
115	1650037	FAS158 Contra-PRW Exclud Med-D	(26,524,765.00)	(27,129,823.01)	(27,734,881.02)	(27,734,881.02)	(27,734,881.02)
116	1710010	Interest Under Recover - LA	-	-	-	-	-
117	1710048	Interest Receivable -FIT -LT	1,918.00	(19,483.00)	(19,483.00)	(19,483.00)	(19,483.00)
118	1710348	Interest Receivable -SIT -LT	-	-	-	-	-
119	1720000	Rents Receivable	746,892.76	808,671.40	945,418.90	945,419.00	945,419.00
120	1730003	Acrd Utility Rev-West	55,255,000.49	57,911,515.27	56,833,992.34	56,833,992.00	56,833,992.00

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121	1740000	Misc Current & Accrued Assets	-	-	-	-	-
122	1750001	Curr. Unreal Gains - NonAffil	3,105,084.96	7,438,163.34	7,768,208.26	7,768,208.00	7,768,208.00
123	1750002	Long-Term Unreal Gns - Non Aff	42,021.00	36,834.00	11,622.00	11,622.00	11,622.00
124	1750021	S/T Asset MTM Collateral	(83,482.00)	(65,042.00)	(46,143.00)	(46,143.00)	(46,143.00)
125	1750022	L/T Asset MTM Collateral	(12,111.00)	(9,139.00)	(2,893.00)	(2,893.00)	(2,893.00)
126	1810002	Unamort Debt Exp - Inst Pur Cn	26,610.57	23,805.92	21,001.27	20,844.00	30,459.00
127	1810003	Unamort Debt Exp Notes Payable	240,235.24	264,148.62	253,062.00	251,170.00	367,029.00
128	1810006	Unamort Debt Exp - Sr Unsec Nt	14,134,301.93	14,034,501.87	13,934,701.81	13,830,512.00	20,210,224.00
129	1810102	Unamort Debt Exp-PCB Ins	-	-	-	-	-
130	1823000	Other Regulatory Assets	98,981.00	2,700,286.00	2,687,821.00	2,680,857.00	2,673,892.00
131	1823010	Energy Efficiency Recovery	3,550,460.15	3,126,106.89	2,306,630.17	2,300,654.00	2,294,677.00
132	1823075	Def Exp Selling Price Variance	2,135,225.94	2,606,733.65	2,992,376.31	2,984,624.00	2,976,869.00
133	1823077	Unreal Loss on Fwd Commitments	717,081.10	1,099,810.83	1,186,645.52	1,183,571.00	1,180,496.00
134	1823099	Asset Retirement Obligations	5,047,046.70	5,159,214.06	5,268,598.96	5,254,949.00	5,241,296.00
135	1823108	Reg Asset - Rate Case Expenses	5,944,541.23	5,675,163.00	5,357,104.17	5,343,225.00	5,329,343.00
136	1823149	Unrecovered Fuel Cost - LA	545,300.89	3,227.00	0.00	-	-
137	1823150	Unrecovered Fuel Cost - AR	17,253,023.49	16,031,976.89	15,763,674.15	(1,706,378.00)	(1,232,019.00)
138	1823165	REG ASSET FAS 158 QUAL PLAN	95,038,202.25	93,785,518.50	93,785,518.50	93,542,541.00	93,299,506.00
139	1823166	REG ASSET FAS 158 OPEB PLAN	(3,047,164.52)	(2,340,980.79)	(2,340,980.79)	(2,334,916.00)	(2,328,849.00)
140	1823167	REG Asset FAS 158 SERP Plan	1,115,587.25	1,101,194.50	1,101,194.50	1,098,342.00	1,095,488.00
141	1823180	Deferred Storm Expense	(0.00)	(0.00)	-	-	-
142	1823219	Under Recovered EAC - LA	37,521.76	189,578.99	166,885.90	(18,065.00)	(13,043.00)
143	1823241	Valley District Due Diligence	-	-	0.00	-	-
144	1823299	SFAS 106 Medicare Subsidy	3,510,955.89	3,466,513.39	3,422,070.89	3,413,205.00	3,404,337.00
145	1823301	SFAS 109 Flow Thru Defd FIT	69,705,118.82	69,598,451.25	69,501,853.26	69,501,853.00	69,501,853.00
146	1823302	SFAS 109 Flow Thru Defrd SIT	191,354,909.00	190,948,243.00	191,121,231.00	191,121,231.00	191,121,231.00
147	1823306	Net CCS FEED Study Costs	446,858.73	446,858.73	446,858.73	445,701.00	444,543.00
148	1823324	LA FRP Asset	135,858.80	128,008.15	120,157.51	119,846.00	119,535.00
149	1823348	Louisiana Vegetation Managemnt	(0.00)	(0.00)	(0.00)	-	-
150	1823359	SWEPCo Transmission Recovery	2,992,369.00	2,720,335.45	2,448,301.90	2,441,959.00	2,435,614.00
151	1823360	2010 Severance Costs	-	-	0.00	-	-
152	1823374	Environmental Chemical Cost-AR	2,515,590.13	2,616,570.34	2,710,958.77	2,703,935.00	2,696,910.00
153	1823377	NBV - AROs Retired Plants	505,227.03	504,633.69	504,040.35	502,734.00	501,428.00
154	1823424	LA 2015 FRP Asset-SPP Deferral	5,011,871.33	5,053,550.92	5,095,230.51	5,082,030.00	5,068,826.00
155	1823425	LA 2015 FRP Asset - Contra	(239,169.08)	(258,643.64)	(278,118.20)	(277,398.00)	(276,677.00)
156	1823428	Welsh 2 TX Portion Undepr Bal	17,374,258.66	17,333,481.51	17,292,607.89	17,247,807.00	17,202,995.00
157	1823539	Facilities Maint SWEPCO LA	652,503.20	664,020.75	665,697.46	663,973.00	662,248.00
158	1823554	WELSH/FLINT CREEK ENVIRONM DEF	22,870,786.98	22,733,836.16	22,596,885.34	22,538,342.00	22,479,785.00
159	1823555	WELSH/FLINTCREEK ENVIR-CONTRA	(7,999,554.25)	(7,951,652.73)	(7,903,751.21)	(7,883,274.00)	(7,862,793.00)
160	1830000	Prelimin Surv&Investgtn Chrgs	1,327,619.08	1,544,920.48	1,668,269.01	1,668,269.00	1,668,269.00

Supporting Schedules:
(a) E-17B

Recap Schedules:
(A)Schedule B-4

Southwestern Electric Power Company
Average Working Capital Asset Account Balances
Test Year Ending December 31, 2018
Docket No. 19-008-U

Schedule B-5

Explanation: Schedule showing balances for all assets other than plant accounts by subaccount for the 13 months ending with the last month of the test year. Subaccount Descriptions should provide a detailed discussion of the purposes of the subaccount, using examples if needed.

Line No	Account	Description	Balance 5/31/18(a)	Balance 6/30/18(a)	Balance 7/31/18(a)	Balance 8/31/18(a)	Balance 9/30/18(a)
161	1840002	Accounts Pay Adj - Clearing	(40.00)	-	(3,195.44)	(3,195.00)	(3,195.00)
162	1840019	CMS & CMF - Clearing Activity	(0.00)	(0.00)	-	-	-
163	1840033	Alliance Rail Car - OH	(8,970.13)	65,143.64	101,172.46	101,172.00	101,172.00
164	1840035	IT Oper Company (OPCO) Clearng	(0.00)	(0.00)	-	-	-
165	1860001	Allowances	2,042.03	1,417.03	1,417.03	1,417.00	1,417.00
166	1860002	Deferred Expenses	(130,274.84)	691.88	(11,568.68)	(11,569.00)	(11,569.00)
167	186000316	Deferred Property Taxes	-	-	-	-	-
168	186000318	Deferred Property Taxes	37,866,657.00	31,557,855.67	26,298,280.67	20,901,968.00	15,505,655.00
169	1860005	Unidentified Cash Receipts	(486.50)	-	(100.00)	(100.00)	(100.00)
170	1860007	Billings and Deferred Projects	5,084,328.64	3,469,660.46	3,627,130.08	3,621,566.00	3,616,003.00
171	1860015	Billings Paid Union Benefits	8,429.49	-	2,473.12	2,473.00	2,473.00
172	1860046	Railroad Cars Subleased	9,345.59	-	7,848.00	7,848.00	7,848.00
173	1860077	Agency Fees - Factored A/R	3,089,794.27	3,777,378.19	4,001,983.68	4,001,984.00	4,001,984.00
174	186008118	Defd Property Tax - Cap Lease	100,915.00	86,498.00	72,081.00	57,290.00	42,499.00
175	1860089	Reclamation Advance	14,984,878.04	13,977,984.53	13,408,216.38	13,408,216.00	13,408,216.00
176	1860150	Deferred Rate Case Expense	92,690.39	72,947.89	92,947.89	92,948.00	92,948.00
177	1860153	Unamortized Credit Line Fees	401,493.99	387,719.79	373,945.59	373,946.00	373,946.00
178	1860154	Affl Deferred Tran(IPP) Credit	-	-	-	-	-
179	1860156	Sabine Mine Rusk Preparation	13,592,925.22	13,533,287.31	13,483,530.82	13,483,531.00	13,483,531.00
180	1860160	Deferred Expenses - Current	239,671.45	324,860.85	424,483.96	424,484.00	424,484.00
181	1860166	Def Lease Assets - Non Taxable	-	16,970.87	16,970.87	16,971.00	16,971.00
182	1860171	Marshall South Mine Prep	-	-	(0.00)	-	-
183	1860185	Long Term Assoc AR	-	1,266,807.50	1,266,807.50	1,266,807.00	1,266,807.00
184	1890001	Loss Recqd Debt - FMB	2,264,750.39	2,247,541.94	2,230,333.49	2,219,368.00	2,208,403.00
185	1890002	Loss Rec Debt-Ins Purch Cont	166,602.27	162,513.71	158,425.15	157,646.00	156,867.00
186	1890004	Loss Rec Debt-Debentures	1,983,167.36	1,963,510.39	1,943,853.43	1,934,297.00	1,924,740.00
187	1900011	ADIT Federal Non-UMWA PRW OCI	(508,594.00)	(417,286.10)	(417,286.10)	(417,286.00)	(417,286.00)
188	1900015	ADIT-Fed-Hdg-CF-Int Rate	1,703,742.95	1,665,021.53	1,626,300.11	1,626,300.00	1,626,300.00
189	1901001	Accum Deferred FIT - Other	58,809,814.67	64,313,249.32	65,590,230.70	65,590,231.00	65,590,231.00
190	1901002	Accum Deferred SIT - Other	48,923,746.89	47,097,817.16	47,097,817.16	47,097,817.00	47,097,817.00
191	1902001	Accum Defd FIT - Oth Inc & Ded	944,034.82	809,004.82	673,974.82	673,975.00	673,975.00
192	1903001	Acc Dfd FIT - FAS109 Flow Thru	41,746,093.95	41,628,921.29	41,633,476.03	41,633,476.00	41,633,476.00
193	1904001	Accum Dfd FIT - FAS 109 Excess	148,876,233.42	148,642,099.63	148,407,965.83	148,407,966.00	148,407,966.00
		Total	1,208,557,888.90	1,232,038,107.22	1,237,712,465.92	1,215,258,553.72	1,697,495,081.72

Subaccount Descriptions:
Refer to Schedule E-9

Supporting Schedules:
(a) E-17B

Recap Schedules:
(A)Schedule B-4

Southwestern Electric Power Company
Average Working Capital Asset Account Balances
Test Year Ending December 31, 2018
Docket No. 19-008-U

Schedule B-5

Explanation: Schedule showing balances for all assets other than plant accounts by subaccount for the 13 months ending with the last month of the test year. Subaccount Descriptions should provide a detailed discussion of the purposes of the subaccount, using examples if needed.

Line No	Account	Description	Forecasted Balance 10/31/18(a)	Balance 11/30/18(a)	Balance 12/31/18(a)	13 Months(A) Average
1	1010006	Dolet Hills FAS 143 ARO Asset	41,520,820.72	41,520,820.72	41,520,820.72	29,838,448.49
2	1011001	Capital Leases	47,912,413.00	47,912,413.00	47,912,413.00	47,645,458.88
3	1011012	Accrued Capital Leases	124,546.00	124,546.00	124,546.00	247,530.33
4	1011006	Prov-Leased Assets	(21,116,832.00)	(21,116,832.00)	(21,116,832.00)	(20,841,594.67)
5	1080012	Dolet Hills FAS 143 ARO Deprec	(6,880,862.00)	(6,917,458.00)	(6,924,295.00)	(6,671,987.21)
6	1080013	ARO Removal Deprec - Accretion	6,820,560.00	6,839,837.00	6,859,481.00	6,664,153.99
7	1160007	OthElecPltAdjTurkImprmnt-EPIS	(58,098,551.00)	(57,993,910.00)	(57,889,147.00)	(58,291,240.45)
8	1160008	TurkAFUDCReverseTXCap-EPIS	(1,306,036.00)	(1,303,684.00)	(1,301,329.00)	(1,310,367.62)
9	1160009	AmortTurkImprmnt&AFUDCReversal	6,061,354.00	6,050,436.00	6,039,507.00	5,886,663.23
10	1160012	Turk Imprmnt-AuxBoiler	(18,400,806.00)	(18,367,664.00)	(18,334,484.00)	(18,461,833.62)
11	1160013	Turk Imprmnt-AuxBoiler Amort	1,970,225.00	1,966,676.00	1,963,124.00	1,909,020.92
12	1160016	TX Trans Veg Mgmt Cost Wrteoff	(1,433,327.00)	(1,430,746.00)	(1,428,161.00)	(1,358,499.34)
13	1160017	TX Distr Veg Mgmt Cost Wrteoff	(4,081,574.00)	(4,074,223.00)	(4,066,863.00)	(4,096,978.54)
14	1160018	TX Dist Veg Mgt WriteOff Amort	308,718.00	308,162.00	307,605.00	289,940.41
15	1160019	TX Tran Veg Mgt WriteOff Amort	60,311.00	60,202.00	60,094.00	56,131.99
16	1160020	TX Trans Costs - SERP	(158,668.00)	(158,382.00)	(158,096.00)	(186,140.70)
17	1160021	TX Distr Costs - SERP	(47,555.00)	(47,470.00)	(47,384.00)	(61,814.16)
18	1160022	TX Gen Costs - SERP	(299,348.00)	(298,809.00)	(298,269.00)	(731,761.24)
19	1160023	TX CWIP FinBased Incen - Trans	(1,737,976.00)	(1,734,846.00)	(1,731,712.00)	(1,571,084.18)
20	1160024	TX CWIP FinBased Incen - Distr	(2,095,734.00)	(2,091,959.00)	(2,088,180.00)	(1,909,987.75)
21	1160025	TX CWIP FinBased Incen - Gen	(2,454,892.00)	(2,450,471.00)	(2,446,044.00)	(2,253,226.43)
22	1160026	TX RWIP FinBased Incen - Trans	(63,555.00)	(63,440.00)	(63,326.00)	(58,487.61)
23	1160027	TX RWIP FinBased Incen - Distr	(84,215.00)	(84,063.00)	(83,911.00)	(76,318.34)
24	1160028	TX RWIP FinBased Incen - Gen	(93,587.00)	(93,419.00)	(93,250.00)	(86,409.60)
25	1230000	Invest Nonconsol Assoc Co	806,112.00	958,829.00	1,075,785.00	287,836.15
26	1231003	Capital Contributions to Subs	100,000.00	100,000.00	100,000.00	100,000.00
27	1231005	Invest in Subs Retained Erngs	1,892,064.00	1,892,064.00	1,892,064.00	1,885,813.86
28	1231101	Invest Nonconsol Subs-Equity	24,759,407.00	24,759,407.00	24,759,407.00	24,759,406.92
29	1231102	Equity in Erngs Nonconsol Subs	13,766,159.00	13,766,159.00	13,766,159.00	13,287,285.09
30	1240002	Oth Investments-Nonassociated	1,454,009.00	1,644,009.00	1,833,009.00	1,099,162.62
31	1240027	Other Property - RWIP	3,498.00	3,498.00	3,498.00	2,073.74
32	1240029	Other Property - CPR	301,444.00	301,444.00	301,444.00	301,443.71
33	1290001	Non-UMWA PRW Funded Position	27,855,898.00	27,855,898.00	27,855,898.00	28,645,809.43
34	1290002	SFAS 106 - Non-UMWA PRW	4,207,041.00	4,207,041.00	4,207,041.00	2,912,309.55
35	1310000	Cash	1,625,000.00	1,625,000.00	1,625,000.00	1,761,309.77
36	1340018	Spec Deposits - Elect Trading	4,560,652.00	4,560,652.00	4,560,652.00	2,158,854.89
37	1340046	Deposits-O&M Dolet Hills Plant	3,348,000.00	3,348,000.00	3,348,000.00	4,622,127.66
38	1340048	Spec Deposits-Trading Contra	49,036.00	49,036.00	49,036.00	84,150.08
39	1340050	Spec Deposit Mizuho Securities	-	-	-	-
40	1340051	Spec Depost RBC	37,411.00	37,411.00	37,411.00	25,521.89

Supporting Schedules:
(a) E-17B

Recap Schedules:
(A)Schedule B-4

Southwestern Electric Power Company
Average Working Capital Asset Account Balances
Test Year Ending December 31, 2018
Docket No. 19-008-U

Schedule B-5

Explanation: Schedule showing balances for all assets other than plant accounts by subaccount for the 13 months ending with the last month of the test year. Subaccount Descriptions should provide a detailed discussion of the purposes of the subaccount, using examples if needed.

Line No	Account	Description	Forecasted Balance 10/31/18(a)	Balance 11/30/18(a)	Balance 12/31/18(a)	13 Months(A) Average
41	1340053	Deposits - Flexible Spending	90,164.00	90,164.00	90,164.00	90,164.04
42	1420001	Customer A/R - Electric	137,139,619.00	137,139,619.00	137,139,619.00	119,131,521.27
43	1420006	A/R-Customer Assistance	-	-	-	126.62
44	1420014	Customer A/R-System Sales	15,272,820.00	15,272,820.00	15,272,820.00	15,714,831.59
45	1420022	Cust A/R - Factored	(144,670,792.00)	(144,670,792.00)	(144,670,792.00)	(122,583,872.00)
46	1420023	Cust A/R-System Sales - MLR	251,008.00	251,008.00	251,008.00	135,051.98
47	1420044	Customer A/R - Estimated	20,640,333.00	20,640,333.00	20,640,333.00	26,811,554.95
48	1420048	Emission Allowance Trading	-	-	-	53.85
49	1420051	MISO AR Accrual	-	-	-	25,052.07
50	1420055	SPP AR Accrual	-	-	-	2,670,103.41
51	1420101	Other Accounts Rec - Cust	563,033.00	563,033.00	563,033.00	474,840.55
52	1420102	AR Peoplesoft Billing - Cust	5,554,690.00	5,554,690.00	5,554,690.00	5,928,140.59
53	1430002	Allowances	20.00	20.00	20.00	28.13
54	1430022	2001 Employee Biweekly Pay Cnv	7,629.00	7,629.00	7,629.00	7,628.98
55	1430080	Jointly Owned Unit O&M Billing	18,340,069.00	18,340,069.00	18,340,069.00	16,720,908.47
56	1430081	Damage Recovery - Third Party	80,593.00	80,593.00	80,593.00	72,048.83
57	1430083	Damage Recovery Offset Demand	(86,479.00)	(86,479.00)	(86,479.00)	(77,436.13)
58	1430086	AR Accrual NYMEX OTC Penults	-	-	-	0.00
59	1430101	Other Accounts Rec - Misc	950,297.00	950,297.00	950,297.00	1,203,723.63
60	1430102	AR Peoplesoft Billing - Misc	931,407.00	931,407.00	931,407.00	1,529,553.04
61	1430103	AR Long-Term-Miscellaneous	901,365.00	901,365.00	901,365.00	1,050,703.64
62	1440002	Uncoll Accts-Other Receivables	(557,715.00)	(557,715.00)	(557,715.00)	(687,324.96)
63	1450000	Corp Borrow Prg (NR-Assoc)	48,118,970.00	23,963,025.00	-	82,725,249.22
64	1460001	A/R Assoc Co - InterUnit G/L	27,115,186.00	27,115,186.00	27,115,186.00	24,559,886.76
65	1460004	A/R Assoc Co - CM Bills	31,878.00	31,878.00	31,878.00	49,586.25
66	1460006	A/R Assoc Co - Intercompany	1,517,769.00	1,517,769.00	1,517,769.00	724,459.30
67	1460009	A/R Assoc Co - InterUnit A/P	22,948.00	22,948.00	22,948.00	15,506.93
68	1460011	A/R Assoc Co - Multi Pmts	10,323,653.00	10,323,653.00	10,323,653.00	7,647,327.40
69	1460025	Fleet - M4 - A/R	16,583.00	16,583.00	16,583.00	23,194.84
70	1510001	Fuel Stock - Coal	43,471,548.00	42,571,313.00	44,950,375.00	42,644,231.43
71	1510002	Fuel Stock - Oil	4,591,541.00	4,591,541.00	4,591,541.00	4,322,187.65
72	1510016	Coal Inv on Hand Transp	11,800.00	11,556.00	12,202.00	12,915.45
73	1510017	Lignite Inv on Hand Inc Transp	26,243,927.00	25,700,452.00	27,136,700.00	29,790,031.74
74	1510018	Coal Survey Adjustment	(872,083.00)	(854,023.00)	(901,750.00)	(724,244.01)
75	1510020	Fuel Stock Coal - Intransit	3,723,456.00	3,646,348.00	3,850,121.00	3,203,961.36
76	1520000	Fuel Stock Exp Undistributed	2,167,938.00	2,167,938.00	2,167,938.00	2,024,458.96
77	1540001	M&S - Regular	66,526,150.00	66,526,150.00	66,526,150.00	66,223,833.01
78	1540004	M&S - Exempt Material	516,794.00	516,794.00	516,794.00	537,837.24
79	1540006	M&S - Lime and Limestone	1,403,684.00	1,403,684.00	1,403,684.00	1,336,831.25
80	1540013	Transportation Inventory	87,066.00	87,066.00	87,066.00	79,583.38

Supporting Schedules:
(a) E-17B

Recap Schedules:
(A)Schedule B-4

Southwestern Electric Power Company
Average Working Capital Asset Account Balances
Test Year Ending December 31, 2018
Docket No. 19-008-U

Schedule B-5

Explanation: Schedule showing balances for all assets other than plant accounts by subaccount for the 13 months ending with the last month of the test year. Subaccount Descriptions should provide a detailed discussion of the purposes of the subaccount, using examples if needed.

Line No	Account	Description	Forecasted Balance 10/31/18(a)	Balance 11/30/18(a)	Balance 12/31/18(a)	13 Months(A) Average
81	1540025	Matls Supply-Activated Carbon	298,572.00	298,572.00	298,572.00	347,676.19
82	1540028	M&S - Anhydrous Ammonia	18,579.00	18,579.00	18,579.00	21,644.73
83	1540030	Matls Supply-Calcium Bromide	57,671.00	57,671.00	57,671.00	57,353.89
84	1581012	CSAPR An. NOx Inv. - Current	(99,768.00)	(99,768.00)	(99,768.00)	(33,929.87)
85	1581014	CSAPR Seas NOx Comp Inv - Curr	112,608.00	112,608.00	112,608.00	102,937.80
86	1630004	Strs Exp-T&D Satellite Storerm	-	-	-	(0.00)
87	1630056	Knox Lee Power Plant	-	-	-	0.00
88	1630059	Pirkey Power Plant	-	-	-	(0.00)
89	1630061	Welsh Power Plant	-	-	-	0.00
90	1650001	Prepaid Insurance	2,063,567.00	2,063,567.00	2,063,567.00	1,402,141.26
91	165000218	Prepaid Taxes	-	-	-	219,002.81
92	1650005	Prepaid Employee Benefits	-	-	-	6,698.20
93	1650006	Other Prepayments	16,914,734.00	16,914,734.00	16,914,734.00	16,936,470.50
94	1650009	Prepaid Carry Cost-Factored AR	179,617.00	179,617.00	179,617.00	177,169.40
95	1650010	Prepaid Pension Benefits	90,896,301.15	90,896,301.15	90,896,301.15	92,344,882.15
96	165000218	Prepaid Taxes	1,125,105.00	1,125,105.00	1,125,105.00	519,279.25
97	165001116	Prepaid Sales Taxes	-	-	-	-
98	165001117	Prepaid Sales Taxes	-	-	-	(76,651.51)
99	165001118	Prepaid Sales Taxes	1,225,200.00	1,225,200.00	1,225,200.00	1,230,858.08
100	165001216	Prepaid Use Taxes	-	-	-	-
101	165001217	Prepaid Use Taxes	-	-	-	1,545.14
102	165001218	Prepaid Use Taxes	159.00	159.00	159.00	2,734.08
103	165001316	Prepaid Local Franchise Taxes	-	-	-	-
104	165001317	Prepaid Local Franchise Taxes	-	-	-	4,451.14
105	165001318	Prepaid Local Franchise Taxes	53,575.00	53,575.00	53,575.00	50,477.25
106	1650014	FAS 158 Qual Contra Asset	(90,896,301.15)	(90,896,301.15)	(90,896,301.15)	(92,344,882.15)
107	1650016	FAS 112 ASSETS	-	-	-	-
108	1650017	Prepayment - Coal	4,200,175.00	4,200,175.00	4,200,175.00	4,935,032.22
109	1650018	Affl Trans Intercon Providers	-	-	-	(0.00)
110	1650021	Prepaid Insurance - EIS	3,126,986.00	3,126,986.00	3,126,986.00	2,068,803.78
111	1650023	Prepaid Lease	183,784.00	183,784.00	183,784.00	187,814.57
112	1650029	Future Wetlands Credits L-T	300,000.00	300,000.00	300,000.00	300,000.00
113	1650030	Other Prepayments - Long Term	1,709,806.00	1,709,806.00	1,709,806.00	1,326,475.74
114	1650035	PRW Without MED-D Benefits	27,734,881.02	27,734,881.02	27,734,881.02	26,440,149.81
115	1650037	FAS158 Contra-PRW Exclud Med-D	(27,734,881.02)	(27,734,881.02)	(27,734,881.02)	(26,440,149.81)
116	1710010	Interest Under Recover - LA	-	-	-	-
117	1710048	Interest Receivable -FIT -LT	(19,483.00)	(19,483.00)	(19,483.00)	(9,658.00)
118	1710348	Interest Receivable -SIT -LT	-	-	-	-
119	1720000	Rents Receivable	945,419.00	945,419.00	945,419.00	884,409.90
120	1730003	Acrd Utility Rev-West	56,833,992.00	56,833,992.00	56,833,992.00	46,158,041.26

Supporting Schedules:
(a) E-17B

Recap Schedules:
(A)Schedule B-4

Southwestern Electric Power Company **Schedule B-5**
Average Working Capital Asset Account Balances
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing balances for all assets other than plant accounts by subaccount for the 13 months ending with the last month of the test year. Subaccount Descriptions should provide a detailed discussion of the purposes of the subaccount, using examples if needed.

			Forecasted			13 Months(A)
Line No	Account	Description	Balance 10/31/18(a)	Balance 11/30/18(a)	Balance 12/31/18(a)	Average
121	1740000	Misc Current & Accrued Assets	-	-	-	6,246.27
122	1750001	Curr. Unreal Gains - NonAffil	7,768,208.00	7,768,208.00	7,768,208.00	5,928,509.37
123	1750002	Long-Term Unreal Gns - Non Aff	11,622.00	11,622.00	11,622.00	12,606.77
124	1750021	S/T Asset MTM Collateral	(46,143.00)	(46,143.00)	(46,143.00)	(81,095.23)
125	1750022	L/T Asset MTM Collateral	(2,893.00)	(2,893.00)	(2,893.00)	(3,054.85)
126	1810002	Unamort Debt Exp - Inst Pur Cn	30,244.00	30,028.00	29,813.00	32,754.06
127	1810003	Unamort Debt Exp Notes Payable	364,434.00	361,838.00	359,243.00	292,827.72
128	1810006	Unamort Debt Exp - Sr Unsec Nt	20,067,316.00	19,924,408.00	19,781,500.00	15,561,406.95
129	1810102	Unamort Debt Exp-PCB Ins	-	-	-	2,966.76
130	1823000	Other Regulatory Assets	2,666,925.00	2,659,957.00	2,652,987.00	1,502,000.54
131	1823010	Energy Efficiency Recovery	2,288,698.00	2,282,718.00	2,276,736.00	2,880,952.29
132	1823075	Def Exp Selling Price Variance	2,969,113.00	2,961,355.00	2,953,595.00	1,875,510.77
133	1823077	Unreal Loss on Fwd Commitments	1,177,420.00	1,174,344.00	1,171,267.00	921,713.53
134	1823099	Asset Retirement Obligations	5,227,640.00	5,213,981.00	5,200,318.00	5,013,314.81
135	1823108	Reg Asset - Rate Case Expenses	5,315,457.00	5,301,568.00	5,287,676.00	5,884,105.72
136	1823149	Unrecovered Fuel Cost - LA	-	-	-	496,052.24
137	1823150	Unrecovered Fuel Cost - AR	(819,971.00)	(440,294.00)	82,904.00	9,411,849.82
138	1823165	REG ASSET FAS 158 QUAL PLAN	93,056,415.00	92,813,265.00	92,570,059.00	94,372,314.44
139	1823166	REG ASSET FAS 158 OPEB PLAN	(2,322,782.00)	(2,316,712.00)	(2,310,642.00)	(2,822,876.99)
140	1823167	REG Asset FAS 158 SERP Plan	1,092,634.00	1,089,779.00	1,086,923.00	1,107,865.90
141	1823180	Deferred Storm Expense	-	-	-	(0.00)
142	1823219	Under Recovered EAC - LA	(8,681.00)	(4,661.00)	878.00	70,111.05
143	1823241	Valley District Due Diligence	-	-	-	3,811.39
144	1823299	SFAS 106 Medicare Subsidy	3,395,467.00	3,386,595.00	3,377,721.00	3,507,560.16
145	1823301	SFAS 109 Flow Thru Defd FIT	69,501,853.00	69,501,853.00	69,501,853.00	69,594,344.71
146	1823302	SFAS 109 Flow Thru Defrd SIT	191,121,231.00	191,121,231.00	191,121,231.00	190,703,453.31
147	1823306	Net CCS FEED Study Costs	443,385.00	442,226.00	441,067.00	448,201.27
148	1823324	LA FRP Asset	119,223.00	118,912.00	118,600.00	136,707.25
149	1823348	Louisiana Vegetation Managemnt	-	-	-	(0.00)
150	1823359	SWEPCo Transmission Recovery	2,429,268.00	2,422,921.00	2,416,572.00	2,817,642.55
151	1823360	2010 Severance Costs	-	-	-	31,146.99
152	1823374	Environmental Chemical Cost-AR	2,689,883.00	2,682,855.00	2,675,825.00	2,514,074.80
153	1823377	NBV - AROs Retired Plants	500,122.00	498,815.00	497,508.00	503,811.02
154	1823424	LA 2015 FRP Asset-SPP Deferral	5,055,619.00	5,042,409.00	5,029,196.00	4,974,197.92
155	1823425	LA 2015 FRP Asset - Contra	(275,956.00)	(275,235.00)	(274,514.00)	(227,853.87)
156	1823428	Welsh 2 TX Portion Undepr Bal	17,158,172.00	17,113,339.00	17,068,496.00	17,328,519.01
157	1823539	Facilities Maint SWEPCO LA	660,522.00	658,796.00	657,070.00	626,907.64
158	1823554	WELSH/FLINT CREEK ENVIRONM DEF	22,421,213.00	22,362,629.00	22,304,030.00	22,824,284.98
159	1823555	WELSH/FLINTCREEK ENVIR-CONTRA	(7,842,306.00)	(7,821,815.00)	(7,801,319.00)	(7,983,289.17)
160	1830000	Prelimin Surv&Investgtn Chrgs	1,668,269.00	1,668,269.00	1,668,269.00	1,444,678.39

Supporting Schedules:
(a) E-17B

Recap Schedules:
(A)Schedule B-4

Southwestern Electric Power Company
Average Working Capital Asset Account Balances
Test Year Ending December 31, 2018
Docket No. 19-008-U

Schedule B-5

Explanation: Schedule showing balances for all assets other than plant accounts by subaccount for the 13 months ending with the last month of the test year. Subaccount Descriptions should provide a detailed discussion of the purposes of the subaccount, using examples if needed.

Line No	Account	Description	Forecasted Balance 10/31/18(a)	Balance 11/30/18(a)	Balance 12/31/18(a)	13 Months(A) Average
161	1840002	Accounts Pay Adj - Clearing	(3,195.00)	(3,195.00)	(3,195.00)	(1,477.73)
162	1840019	CMS & CMF - Clearing Activity	-	-	-	(0.00)
163	1840033	Alliance Rail Car - OH	101,172.00	101,172.00	101,172.00	69,887.10
164	1840035	IT Oper Company (OPCO) Clearng	-	-	-	(0.00)
165	1860001	Allowances	1,417.00	1,417.00	1,417.00	1,565.58
166	1860002	Deferred Expenses	(11,569.00)	(11,569.00)	(11,569.00)	(80,716.07)
167	186000316	Deferred Property Taxes	-	-	-	-
168	186000318	Deferred Property Taxes	10,109,342.00	4,713,029.00	(683,284.00)	27,063,950.87
169	1860005	Unidentified Cash Receipts	(100.00)	(100.00)	(100.00)	(318.82)
170	1860007	Billings and Deferred Projects	3,764,911.00	3,756,008.00	3,747,320.00	3,856,553.64
171	1860015	Billings Paid Union Benefits	2,473.00	2,473.00	2,473.00	2,579.06
172	1860046	Railroad Cars Subleased	7,848.00	7,848.00	7,848.00	6,993.17
173	1860077	Agency Fees - Factored A/R	4,001,984.00	4,001,984.00	4,001,984.00	3,467,072.98
174	186008118	Defd Property Tax - Cap Lease	27,709.00	12,918.00	(1,873.00)	72,759.00
175	1860089	Reclamation Advance	13,408,216.00	13,408,216.00	13,408,216.00	14,753,807.06
176	1860150	Deferred Rate Case Expense	92,948.00	92,948.00	92,948.00	88,896.11
177	1860153	Unamortized Credit Line Fees	373,946.00	373,946.00	373,946.00	411,447.42
178	1860154	Affl Deferred Tran(IPP) Credit	-	-	-	-
179	1860156	Sabine Mine Rusk Preparation	13,483,531.00	13,483,531.00	13,483,531.00	13,587,111.28
180	1860160	Deferred Expenses - Current	424,484.00	424,484.00	424,484.00	321,133.86
181	1860166	Def Lease Assets - Non Taxable	16,971.00	16,971.00	16,971.00	71,201.92
182	1860171	Marshall South Mine Prep	-	-	-	4,094.43
183	1860185	Long Term Assoc AR	1,266,807.00	1,266,807.00	1,266,807.00	682,126.92
184	1890001	Loss Recqd Debt - FMB	2,197,438.00	2,186,472.00	2,175,507.00	2,254,745.57
185	1890002	Loss Rec Debt-Ins Purch Cont	156,088.00	155,310.00	154,531.00	171,102.83
186	1890004	Loss Rec Debt-Debentures	1,915,183.00	1,905,626.00	1,896,069.00	1,975,164.42
187	1900011	ADIT Federal Non-UMWA PRW OCI	(417,286.00)	(417,286.00)	(417,286.00)	(480,499.22)
188	1900015	ADIT-Fed-Hdg-CF-Int Rate	1,626,300.00	1,626,300.00	1,626,300.00	1,707,713.99
189	1901001	Accum Deferred FIT - Other	65,590,231.00	65,590,231.00	65,590,231.00	64,837,547.27
190	1901002	Accum Deferred SIT - Other	47,097,817.00	47,097,817.00	47,097,817.00	47,618,604.09
191	1902001	Accum Defd FIT - Oth Inc & Ded	673,975.00	673,975.00	673,975.00	964,808.73
192	1903001	Acc Dfd FIT - FAS109 Flow Thru	41,633,476.00	41,633,476.00	41,633,476.00	41,614,176.33
193	1904001	Accum Dfd FIT - FAS 109 Excess	148,407,966.00	148,407,966.00	148,407,966.00	148,963,660.01
		Total	1,254,680,031.72	1,223,877,327.72	1,198,881,246.72	1,292,457,712.86

Subaccount Descriptions:
Refer to Schedule E-9

Supporting Schedules:
(a) E-17B

Recap Schedules:
(A)Schedule B-4

Southwestern Electric Power Company
Non-Utility Property & Entertainment Facilities
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE B-6

Explanation: List of all non-utility property and entertainment facilities held by the utility. This schedule is not required unless the Company is proposing to include some portion of these items in its cost of service.

(1) Line No.	(2) Account No.	(3) Type of Property	(4) Actual Amount per Trial Balance at End of Historical Portion of Test Year (a)	(5) Adjustments for Projected Portion of Test Year*	(6) Total Test Year (Col. 4 + Col. 5)
1	121	N/A - Excluded from Rate Base			
2	121				
3	121				
4	121				
5	121				
6	121				
7	121				
8	121				-
9	121				-
10	121				-
11	121				-
12	121				-
13	121				-
14	121				-
15	121				-
16	121				-
17	121				-
18	121				-
19	121				-
20	121				-
21	121				-
22	121				-
23	121				-
24	121				-
25	121				-
26	121				-
27	121				-
28	121				-
29	121				-
30	121				-
31	121				-
32	121				-
33	121				-
34	121				-
35	121				-
36	121				-
37	121				-
38	121				-
39	121				-
40	121	Total Non-Utility Property	-	-	-
41	122	Accumulated Depreciation Non-Utility			
42		Total (A)	-	-	-

*Use this column only if the test period is partially projected

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Supporting Schedules:

Recap Schedules

Southwestern Electric Power Company **SCHEDULE B-7**
Plant Held for Future Use
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: List of plant held for future use by utility, subtotaled by function. This schedule is not required unless the Company is proposing to include some portion of these items in its cost of service.

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
					Plant Held for Future Use			Rents/Revenue Received		
Line No.	Account Number	Acquisition Date	Type of Property	Explanation of Projected Use	Actual Amount per Trial Balance at End of Historical Portion of Test Year (a)	Adjustments for Projected Portion of Test Year*	Total Test Year (Col. 6 + Col. 7)	Actual Amount per Trial Balance at End of Historical Portion of Test Year (a)	Adjustments for Projected Portion of Test Year*	Total Test Year (Col. 9 + Col. 10)
1	36000	2008	LAND	Brush Creek Station - In-Service expected 2018	148,659	-	148,659	-	-	-
2	36000	2007	LAND	Cardnell Road 138KV Substation - In-Service expected 2020	393,043	-	393,043	-	-	-
3	36000	2008	LAND	Meriwether 138KV Substation - In-Service expected 2023	186,713	-	186,713	-	-	-
4	36000	2008	LAND	Shreve Park 138KV Substation - In-Service expected 2023	38,535	-	38,535	-	-	-
5	36000	2017	LAND	Shreveport Bossier Operations Center	20,135	-	20,135	-	-	-
6	31000	2015	LAND	Turk Generating Plant	204,896	-	204,896	-	-	-
7	36000	2008	LAND	East Cotton 69kV Substation - In-Service expected 2023	78,941	-	78,941	-	-	-
8	36000	2015	LAND	Weir Substation - In-Service expected 2022	220,915	-	220,915	-	-	-
9							-	-	-	-
10							-	-	-	-
11							-	-	-	-
12							-	-	-	-
13							-	-	-	-
14							-	-	-	-
15				Total (A)	1,291,835	-	1,291,835	0	0	0
16				Adjustment to remove Turk Plant Related Items		(204,896)	(204,896)			
17										
18										
19										
20				Total Adjustments	-	(204,896)	(204,896)	-	-	-
21										
22				Total (A)	1,291,835	(204,896)	1,086,940	0	0	0

Supporting Schedules:
(a) E-17

Recap Schedules
B-1
(A) B-3

Southwestern Electric Power Company **SCHEDULE B-8**
Schedule of Construction Work In Progress
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: A schedule of individual construction projects, grouped by function, that support the test year amount of CWIP included on Schedule B-3 and proposed additions to Gross Plant on Schedule B-2. Subtotals should be included for each function. All projects under $500,000 may be grouped by function by Major Gas and Electric utilities and projects under $250,000 may be grouped by function by Non-Major utilities.

Line No.	Function	(1) Project Identifying Number	(2) Description of Construction	(3) Rounded Historical CWIP as of 7/31/2018 (A)	(4) 2018 Additions	(5) 2018 CWIP Completed	(5a) CWIP Balance At end of Test Year 12/31/2018	(6) Date of Last Construction Activity	(6a) Projected Start Date of Projects to Started in Proforma Year	(6b) Projected Date of Completion and Inclusion in Gross Plant	(7) CWIP Balance at Beginning Proforma Year 2019	(8) 2019 Additions	(9) 2019 CWIP Completed	(10) Projected Final Cost of Completed Projects not included in Col. 9 12/31/2019
1	Intangible Plant	ITCAPPROJ	ITCAPPROJ: It Capital Projects	-	17,701,853	13,261,138	4,440,715	201812	201901	Budget Only	4,440,715	1,548,496	6,493,324	(504,113)
2		IT1681421	IT1681421 Maximo Imp - SEP - G	4,153,458	-	-	4,153,458	N/A	N/A	12/31/2019	4,153,458	-	-	4,153,458
3		IT1591421	IT1591421 Maximo Imp - SEP - D	1,294,047	-	-	1,294,047	N/A	N/A	12/31/2019	1,294,047	-	-	1,294,047
4		IT1941421	IT1941421 Maximo Imp - SEP - T	969,748	-	-	969,748	N/A	N/A	12/31/2019	969,748	-	-	969,748
5		IT1611421	IT1611421 Maximo Imp - SEPT - D	666,410	-	-	666,410	N/A	N/A	12/31/2019	666,410	-	-	666,410
6		IT1111421	IT1111421 Maximo Imp - SEPT - T	500,689	-	-	500,689	N/A	N/A	12/31/2019	500,689	-	-	500,689
7		ITSSV1578	ITSSV1578: Data Center 2	-	2,848,453	2,891,512	(43,059)	201812	201901	3/31/2020	(43,059)	6,024,699	5,930,689	50,951
8		ITPFP1421	ITPFP1421: Maximo Implementation	-	2,737,771	2,787,416	(49,645)	201812	201901	12/31/2019	(49,645)	1,264,991	1,503,168	(287,822)
9		ITSEC1556	ITSEC1556: Cyber IronNet	-	1,226,693	891,673	335,020	201812	201901	12/31/2021	335,020	349,098	688,089	(3,971)
10		ITSSV1604	ITSSV1604: ITMP 2018	-	834,809	847,430	(12,621)	201812	201901	12/31/2018	(12,621)	889	118,982	(130,714)
11		ITSSV1612	ITSSV1612: IT IBM ELA	-	2,969	743,987	(741,018)	201807	N/A	6/30/2020	(741,018)	-	-	(741,018)
12		ITCOP1644	ITCOP1644: COPSFUEL Gas Procur Settle	-	637,126	649,821	(12,695)	201812	201901	3/30/2019	(12,695)	39,000	101,623	(75,318)
13		ITSSV1560	ITSSV1560: NADC Growth	-	566,498	574,995	(8,497)	201808	201901	12/31/2018	(8,497)	606	80,976	(88,867)
14		000018412	000018412: FEL IT Projects	-	559,837	570,990	(11,153)	201812	201901	Blanket	(11,153)	649,111	650,889	(12,931)
15		ITPFP1331	ITPFP1331: Cognos Implementation	-	545,270	552,732	(7,462)	201812	201901	3/31/2020	(7,462)	827,119	838,991	(19,334)
16		ITSSV1596	ITSSV1596: Fleet Vehicle Telematics	-	533,992	538,792	(4,800)	201812	201901	Blanket	(4,800)	457,318	514,131	(61,613)
17		ITSEC1636	ITSEC1636: Cyber Ent Vuln Mgmt & Track	-	529,811	537,823	(8,012)	201812	201901	12/31/2018	(8,012)	5,468	80,027	(82,571)
18		ITSSV1639	ITSSV1639: Storage Lifecycle Growth	-	507,573	515,176	(7,603)	201812	201901	6/30/2018	(7,603)	542	72,342	(79,403)
19		ITSEC1656	ITSEC1656: Cyber-Ann Assmt Rem 2018	-	527,116	509,069	18,047	201812	201901	6/30/2018	18,047	561	75,136	(56,528)
20		ITCOP0001	ITCOP0001: IT Commercial Ops Blanket	-	454,441	463,291	(8,850)	201812	201901	Blanket	(8,850)	520,811	522,491	(10,530)
21		ITSSV0003	ITSSV0003: IT Shared Services Blanket	-	315,636	265,685	49,951	201812	201901	Blanket	49,951	10,888,071	9,486,493	1,451,529
22		DIGITAHUB	DIGITAHUB: Digital Hub Project	-	483,452	255,038	228,414	201812	201901	Budget Only	228,414	2,168,269	2,181,572	215,111
23		ITUOP0005	ITUOP0005: IT Utility Operations Blanket	-	149,900	146,297	3,603	201812	201901	Blanket	3,603	2,218,142	1,901,801	319,944
24		ITSEC1436	ITSEC1436: Security Blanket	-	145,595	97,295	48,300	201812	201901	Blanket	48,300	4,829,686	4,479,860	398,126
25		Less than $500k		364,357	5,318,069	5,563,207	119,219	Various	Various	Various	119,219	3,673,832	4,164,972	(371,921)
26	Intangible Plant Sum			7,948,709	36,626,864	32,663,367	11,912,206				11,912,206	35,466,709	39,885,556	7,493,359
27	Other Generation Plant	Less than $500k		14,246	-	-	14,246	N/A	N/A	Various	14,246	-	-	14,246
28	Other Generation Plant Sum			14,246	-	-	14,246				14,246	-	-	14,246
29	Steam Generation Plant	PRK12C704	PRK12C704: PRK Controls BMS CC	6,920,701	2,972,857	-	9,893,558	201812	201901	7/1/2019	9,893,558	5,046,872	15,905,060	(964,630)
30		WLKCI2004	WLKCI2004: U2 SH&RH Outlet BNK&HDR Repl	6,586,103	(13,182,890)	(13,084,873)	6,488,086	200810	201901	8/30/2018	6,488,086	104	18,135	6,470,055
31		WSX111023	WSX111023 Dolet Hills-Ppb Other Producti	4,739,891	3,240,363	3,307,543	4,672,711	201812	201901	Blanket	4,672,711	6,934,058	6,683,590	4,923,179
32		TRK2LNDFL	TRK2LNDFL TRK ACTIVATE 2 LANDFILL	3,376,862	492,736	492,736	3,376,862	201812	N/A	12/11/2018	3,376,862	-	-	3,376,862
33		WSHCU0019	WSHCU0019 WSH U0 Coal Car Dumper Repla	2,371,333	-	-	2,371,333	N/A	N/A	3/31/2019	2,371,333	-	-	2,371,333
34		GWSCBS168	GWSCBS168: Power Production Blanket SWEP(	-	10,197,334	7,888,358	2,308,976	201812	201901	Budget Only	2,308,976	24,850	2,182,300	151,526
35		ARSCP6B18	ARSCP6B18: STALL 6B LTSA CAPITAL 2018	86,871	15,205,608	13,293,374	1,999,105	201812	201901	12/31/2018	1,999,105	9,840	1,708,221	300,724
36		NRCPSWPCO	NRCPSWPCO NERC CIP SWEPCO	1,980,838	-	-	1,980,838	N/A	N/A	9/28/2018	1,980,838	-	-	1,980,838
37		FLCU10155	FLCU10155 FLC U1B, 4-kV Switchgear Repl	1,637,544	-	-	1,637,544	N/A	N/A	5/31/2018	1,637,544	-	-	1,637,544
38		PRKXENV01	PRKXENV01 Pirkey Landfill Area K Cell 1	1,225,362	31,721	-	1,257,083	201812	201901	12/22/2022	1,257,083	1,085,480	-	2,342,563
39		WSHCU0CBK	WSHCU0CBK WSH CAP BANK 4KV Switchgr	1,100,693	-	-	1,100,693	N/A	N/A	6/29/2018	1,100,693	-	-	1,100,693
40		PRKCFGD60	PRKCFGD60 FGD CONTROLS UPGRADE	879,791	-	-	879,791	N/A	N/A	4/1/2020	879,791	-	-	879,791
41		FLCU10157	FLCU10157 FLC 4KV CH1A1B Switchgear Rpl	879,084	-	-	879,084	N/A	N/A	5/31/2018	879,084	-	-	879,084
42		000020379	000020379 FLC U1 DBA Conver (CCR/ELG)	853,207	-	-	853,207	N/A	N/A	5/31/2020	853,207	-	-	853,207
43		DLHCI0033	DLHCI0033 Construct New Landfill Cell	844,872	-	-	844,872	N/A	N/A	12/31/2020	844,872	-	-	844,872
44		PRKXENV03	PRKXENV03 PRK Landfill 2018 and 2019	679,915	-	-	679,915	N/A	N/A	12/31/2022	679,915	-	-	679,915
45		INCCAPINV	INCCAPINV: Incremental Capital Investment	-	21,170,804	21,025,445	145,359	201812	201903	Contingency	145,359	2,890,764	1,920,420	1,115,703
46		TRKRAILR1	TRKRAILR1: Turk Rail Replacement	-	14,056,346	14,056,346	-	201812	N/A	12/31/2018	-	-	-	-
47		ARS5CONDS	ARS5CONDS: Arsenal Hill #5 Condenser Tub	-	4,626,060	4,626,060	-	201812	N/A	12/28/2018	-	-	-	-
48		WSHCU3005	WSHCU3005: WSH U3 Pulv Cmpnt Changeout	-	3,549,677	3,554,678	(5,001)	201812	201901	Blanket	(5,001)	291,202	292,059	(5,858)
49		X00000296	X00000296 Administrative	-	3,366,093	3,430,994	(64,901)	201812	201901	Blanket	(64,901)	3,810,131	3,825,734	(80,504)
50		PRKXFAN50	PRKXFAN50: ID Fan Blades B	-	2,853,326	2,853,326	-	201812	N/A	12/31/2018	-	-	-	-
51		ARS6ACWPR	ARS6ACWPR: CIRC WATER PUMP REPLACE	112,849	1,306,510	2,265,552	(846,193)	201812	N/A	11/9/2018	(846,193)	-	-	(846,193)
52		ARS6BCWPR	ARS6BCWPR: CIRC WATR PUMP REPLACE U	112,849	1,306,510	2,265,552	(846,193)	201812	N/A	11/9/2018	(846,193)	-	-	(846,193)
53		000021554	000021554 SWEPCO DHLC/Pirkey Land Acq	29,792	2,004,973	2,087,586	(52,821)	201812	201901	12/31/2019	(52,821)	4,775,741	4,347,947	374,973
54		ARS6ASCRR	ARS6ASCRR: Stall U6A SCR Catalyst Replace	-	1,661,423	1,890,030	(228,607)	201812	201903	12/31/2019	(228,607)	992,572	992,571	(228,606)
55		ARS6BSCRR	ARS6BSCRR: Stall U6B SCR Catalyst Replace	-	1,661,423	1,890,030	(228,607)	201812	201903	12/31/2019	(228,607)	1,005,379	1,005,377	(228,605)
56		PRK10C251	PRK10C251: PULV GRINDING TABLES BOWL	96,184	1,077,922	1,077,924	96,182	201812	201903	Blanket	96,182	126,415	126,415	96,182
57		PRKPSC163	PRKPSC163: FGD Duct Wall Linings Replace	-	1,040,195	1,023,557	16,638	201705	201901	Blanket	16,638	97	16,734	1
58		PRKPSC120	PRKPSC120: Fans ID Overhaul	-	634,073	634,072	1	201812	N/A	Blanket	1	-	-	1
59		WLKC00068	WLKC00068: INSTALL WEIR GATE	38,343	590,247	590,247	38,343	201809	N/A	2/28/2019	38,343	-	-	38,343
60		FLCU10482	FLCU10482: Rep lk Sootblower 54 12 & 4	-	553,356	553,357	(1)	201812	N/A	Blanket	(1)	-	-	(1)
61		TRKPULVER	TRKPULVER: TRK PULVERIZER WHEEL REPI	-	344,403	170,871	173,532	201801	201904	Blanket	173,532	366,170	515,308	24,394
62		ARSBAYOU1	ARSBAYOU1: Stall-Bayou Bank Stabilization	45,622	-	-	45,622	N/A	201906	10/31/2019	45,622	1,781,555	1,781,556	45,621
63		TRKRAILRE	TRKRAILRE: TRK RAIL REPLACEMENT	893	-	-	893	N/A	201903	12/31/2019	893	4,154,635	4,154,635	893
64		000021643	000021643: WSH0 Winston Pond Reline (CCR)	-	-	-	-	N/A	201901	5/31/2021	-	584,000	-	584,000
65		FLCSTATOR	FLCSTATOR: FLC Spare Stator Bars	-	-	-	-	N/A	201902	12/31/2019	-	3,472,542	3,472,544	(2)
66		TRKTRBCON	TRKTRBCON: TRK TURB CONTROL REPLACE	-	(971,956)	(971,956)	-	201812	201901	5/28/2021	-	2,825,297	2,604,257	221,040
67		Less than $500k		8,314,921	(25,135,168)	(15,827,941)	(992,306)	Various	Various	Various	(992,306)	48,078,407	11,877,160	35,208,941
68	Steam Generation Plant Sum			42,914,520	54,653,946	59,092,868	38,475,598				38,475,598	88,256,111	63,430,023	63,301,686

Southwestern Electric Power Company
Schedule of Construction Work In Progress
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE B-8

Explanation: A schedule of individual construction projects, grouped by function, that support the test year amount of CWIP included on Schedule B-3 and proposed additions to Gross Plant on Schedule B-2. Subtotals should be included for each function. All projects under $500,000 may be grouped by function by Major Gas and Electric utilities and projects under $250,000 may be grouped by function by Non-Major utilities.

Line No.	Function	(1) Project Identifying Number	(2) Description of Construction	(3) Rounded Historical CWIP as of 7/31/2018 (A)	(4) 2018 Additions	(5) 2018 CWIP Completed	(5a) CWIP Balance At end of Test Year 12/31/2018	(6) Date of Last Construction Activity	(6a) Projected Start Date of Projects to Started in Proforma Year	(6b) Projected Date of Completion and Inclusion in Gross Plant	(7) CWIP Balance at Beginning Proforma Year 2019	(8) 2019 Additions	(9) 2019 CWIP Completed	(10) Projected Final Cost of Completed Projects not included in Col. 9 12/31/2019
69	Transmission Plant	A16806525	A16806525: Mt Pleasant-NaplesTap Phs 1	2,591,702	3,529,505	-	6,121,207	201812	201901	4/26/2019	6,121,207	1,764,238	7,961,834	(76,389)
70		A15706575	A15706575: Whitney Station Rehab	4,162,195	1,637,129	-	5,799,324	201812	201901	6/24/2019	5,799,324	1,836,562	8,445,149	(809,263)
71		A15706573	A15706573: Dyess Station Rehab	3,393,836	2,144,391	-	5,538,227	201812	201901	6/1/2019	5,538,227	522,040	6,058,127	2,140
72		P15127001	P15127001: Leaside Way-Station	2,423,564	3,058,595	-	5,482,159	201812	201901	3/31/2019	5,482,159	610,108	7,616,446	(1,524,179)
73		A16806531	A16806531: Estelline to W Childress Rehab	4,096,769	77,873	-	4,174,642	201812	201901	12/1/2019	4,174,642	769,262	3,950,382	993,522
74		P14154001	P14154001: Ellerbe Road - Lucas 69 KV	558,016	3,590,601	-	4,148,617	201812	201901	2/15/2019	4,148,617	2,284,907	6,699,840	(266,316)
75		A16806521	A16806521: Clarendon to Hedley Rebuild	3,687,345	116,995	-	3,804,340	201812	201901	12/31/2019	3,804,340	2,063,328	6,218,978	(351,310)
76		A16806533	A16806533 Pilgrims Pride-Winfield Rehab	3,729,579	-	-	3,729,579	N/A	N/A	4/30/2020	3,729,579	-	-	3,729,579
77		TA1571311	TA1571311: T/SW - Telecom Modernization P	-	3,662,225	-	3,662,225	201812	201901	Budget Only	3,662,225	264,680	4,251,781	(324,876)
78		A16806003	A16806003: Strklr Tap-Cedarville REC rebu	4,552,655	23,451	1,084,216	3,491,890	201812	201901	12/31/2018	3,491,890	416,748	416,748	3,491,890
79		A16806009	A16806009: Arsenal Hill-Raines Rd rebuild	473,905	2,499,879	-	2,973,784	201812	201901	12/31/2019	2,973,784	3,050,339	7,210,486	(1,186,363)
80		A16806503	A16806503: Shadow for A16806003	3,440,391	12,058	557,471	2,894,978	201812	N/A	12/31/2018	2,894,978	-	-	2,894,978
81		A15706576	A15706576: Bann Station Rehab	2,775,800	60,020	-	2,835,820	201812	201901	1/18/2019	2,835,820	280,601	2,732,413	384,008
82		P17004001	P17004001: Gillrina 69kV Sub: Construct	-	2,720,716	-	2,720,716	201812	201901	4/30/2020	2,720,716	146,630	2,867,348	(2)
83		A16806593	A16806593: Shadow for A16806531	2,104,831	40,009	-	2,144,840	201812	201901	12/1/2019	2,144,840	48,467	1,682,851	510,456
84		A15706C10	A15706C10 Shadow for A15706575	2,133,790	-	-	2,133,790	N/A	N/A	6/24/2019	2,133,790	-	-	2,133,790
85		P16105007	P16105007: Munz City - Station	593,750	1,371,094	-	1,964,844	201812	201901	4/12/2019	1,964,844	1,242,127	4,409,701	(1,202,730)
86		A16806582	A16806582: Shadow for A16806521	1,894,428	44,830	-	1,939,258	201812	201901	12/31/2019	1,939,258	54,304	1,885,545	108,017
87		A15706C43	A15706C43 SEP-Blanchard-NorthMarket-RHB	1,840,016	-	-	1,840,016	N/A	N/A	6/30/2020	1,840,016	-	-	1,840,016
88		B194TXLRE	B194TXLRE T/SW/Non-Specific Work - Line	1,717,053	1,170,640	1,196,091	1,691,602	201812	201901	Blanket	1,691,602	1,219,850	1,340,571	1,570,881
89		TA1880647	TA1880647: SWEPCo T-Stn Emerging Work	-	1,454,530	-	1,454,530	201812	201901	Contingency	1,454,530	1,099,833	3,302,823	(748,460)
90		A16806016	A16806016: Jenkins Tap-Lone Star PP	1,418,073	35,592	-	1,453,665	201812	201901	7/15/2019	1,453,665	933,264	2,387,095	(166)
91		A15706C07	A15706C07: Shadow for A15706576	1,418,532	30,747	-	1,449,279	201812	201901	1/18/2019	1,449,279	3,639	1,259,614	193,304
92		A16806006	A16806006 39th Sub-NW Texarkana: 7.44	1,364,882	-	-	1,364,882	N/A	N/A	5/7/2020	1,364,882	-	-	1,364,882
93		P16105001	P16105001: Cass Tap - Station	439,767	924,802	-	1,364,569	201812	201901	3/22/2019	1,364,569	1,096,465	4,230,914	(1,769,880)
94		A16806587	A16806587 Shadow for A16806525	1,331,188	-	-	1,331,188	N/A	N/A	4/26/2019	1,331,188	-	-	1,331,188
95		P17010001	P17010001: Siloam-W Siloam Line	118,691	1,144,018	-	1,262,709	201812	201901	6/1/2019	1,262,709	2,337,923	4,417,590	(816,958)
96		P15127501	P15127501 Shadow: SWEPCO P15127001	1,249,119	-	-	1,249,119	N/A	N/A	5/1/2018	1,249,119	-	-	1,249,119
97		A16806012	A16806012: Hughes Springs-Lone Star South	506,162	692,406	-	1,198,568	201812	201901	12/2/2020	1,198,568	2,746,839	-	3,945,407
98		B194LALRE	B194LALRE T/SW/Non-Specific Work-Line Bla	1,085,492	1,451,087	1,480,992	1,055,587	201812	201901	Blanket	1,055,587	1,105,237	1,288,987	871,837
99		A16806551	A16806551: ROW:Estelline to West Childres	824,919	226,485	-	1,051,404	201812	201901	6/1/2019	1,051,404	35,171	1,221,155	(134,580)
100		A15706C44	A15706C44 Shadow For A15706C43	949,575	-	-	949,575	N/A	N/A	6/30/2020	949,575	-	-	949,575
101		A15706626	A15706626 T/SWEPCO/IPC 138 GCB 7340 Fa	947,610	-	-	947,610	N/A	N/A	11/30/2018	947,610	-	-	947,610
102		A16806008	A16806008 39th Street-Bann-Sugar Hill ro	934,140	-	-	934,140	N/A	N/A	5/7/2020	934,140	-	-	934,140
103		A16806589	A16806589: Shadow for A16806527	867,653	22,325	-	889,978	201812	201901	9/27/2019	889,978	43,512	955,468	(21,978)
104		B111TXLRE	B111TXLRE T/SW/Shadow for B194TXLRE	868,606	-	-	868,606	N/A	N/A	Blanket	868,606	-	-	868,606
105		P15127007	P15127007: Leaside Way-Summer Grove-TLine	249,450	552,197	-	801,647	201812	201901	12/31/2019	801,647	1,409,205	2,593,492	(382,640)
106		A16806516	A16806516 Shadow for A16806016	728,509	-	-	728,509	N/A	N/A	7/15/2019	728,509	-	-	728,509
107		A15706624	A15706624 Clarendon - Jericho 69kV strs	721,874	-	-	721,874	N/A	N/A	5/1/2018	721,874	-	-	721,874
108		A16806506	A16806506 Shadow for A16806006	701,124	-	-	701,124	N/A	N/A	5/7/2020	701,124	-	-	701,124
109		P15127012	P15127012: Western Electric-Remote End	274,856	400,411	-	675,267	201812	201901	5/31/2019	675,267	798,787	1,669,257	(195,203)
110		B194ARLRE	B194ARLRE: T/SW/Non-Specific Work - Line Blk	669,195	1,353,650	1,381,172	641,673	201812	201901	Blanket	641,673	1,247,210	1,400,463	488,420
111		P15127003	P15127003: Leaside Way-TLine	187,335	416,528	-	603,863	201812	201901	5/31/2019	603,863	1,585,418	2,368,429	(179,148)
112		A16806532	A16806532: AmocoTap-Childress Amoco	556,087	13,051	-	569,138	201812	201901	12/1/2019	569,138	795,915	1,329,058	35,995
113		B111LALRE	B111LALRE T/SW/Shadow for B194LALRE	556,684	-	-	556,684	N/A	N/A	Blanket	556,684	-	-	556,684
114		B194ARSRE	B194ARSRE T/SW/Non-Specific Work-Station	537,921	427,171	436,552	528,540	201812	201901	Blanket	528,540	330,051	383,767	474,824
115		A16806536	A16806536 ROW: Mount Pleasant to DeKalb	524,555	-	-	524,555	N/A	N/A	5/18/2018	524,555	-	-	524,555
116		A16806530	A16806530: Memphis to Estelline	3,837,880	3,047,436	7,642,606	(757,290)	201812	201901	12/3/2018	(757,290)	37,464	37,464	(757,290)
117		A16806529	A16806529: N Huntington to Waldron Rehab	-	(3,180,798)	3,695,711	(6,876,509)	201812	N/A	12/1/2018	(6,876,509)	-	-	(6,876,509)
118		P16082001	P16082001: Chambers Spring Reactor	2,935,378	765,066	3,456,529	243,915	201812	N/A	11/16/2018	243,915	-	-	243,915
119		A16806010	A16806010: Raines Rd-Longwood rebuild	3,392,133	62,114	3,179,367	274,880	201812	N/A	1/31/2019	274,880	-	-	274,880
120		A16806023	A16806023: Greenland-VBI North-VBI ROW	408,828	2,504,011	2,912,913	(74)	201812	N/A	11/30/2018	(74)	-	-	(74)
121		BUDOFFSET	BUDOFFSET: Cash Flow	-	2,048,252	1,981,349	66,903	201812	201901	Budget Only	66,903	12,340	(162,762)	242,005
122		A16806595	A16806595: Shadow for A16806533	1,916,154	41,419	1,914,892	42,681	201812	N/A	4/30/2020	42,681	-	-	42,681
123		TA1870903	TA1870903: SWEPCo T-line Emerging Work	-	1,770,861	1,770,861	-	201812	N/A	Contingency	-	-	-	-
124		B194TXSRE	B194TXSRE T/SW/Non-Specific Work Station I	320,764	1,695,665	1,731,868	284,561	201812	201901	Blanket	284,561	718,599	981,473	21,687
125		A15706570	A15706570: Diana Station Rehab	87	17,275	1,691,297	(1,673,935)	201812	N/A	6/4/2018	(1,673,935)	-	-	(1,673,935)
126		A15706572	A15706572: Patterson Station Work	493,020	1,247,817	1,635,141	105,696	201812	N/A	12/21/2018	105,696	-	-	105,696
127		A16806524	A16806524: ROW: Clarendon - Memphs	660,931	333,030	1,575,008	(581,047)	201812	N/A	6/16/2019	(581,047)	-	-	(581,047)
128		TA1320611	TA1320611: SWEPCo/ Transmission Asset Hea	-	1,551,688	1,551,688	-	201807	N/A	12/31/2023	-	-	-	-
129		DP14S03D0	DP14S03D0: Morton Saline Sub T-STA	645,475	630,131	1,535,352	(259,746)	201812	N/A	10/1/2018	(259,746)	-	-	(259,746)
130		A16806592	A16806592: Shadow for A16806530	1,971,817	23,893	1,520,732	474,978	201812	N/A	12/3/2018	474,978	-	-	474,978
131		A16806510	A16806510: Shadow for A16806010	1,751,669	31,833	1,471,719	311,783	201812	N/A	12/31/2019	311,783	-	-	311,783
132		P17012001	P17012001: IPC 138 kV: Add 2-14 MVAR cap	502,918	784,803	1,416,599	(128,878)	201812	201901	12/13/2018	(128,878)	89,249	89,249	(128,878)
133		A16806527	A16806527: Buford Survey-Naples	1,688,874	(743,235)	1,338,555	(392,916)	201812	201901	9/27/2019	(392,916)	3,603,410	3,603,410	(392,916)
134		A15706C17	A15706C17: Shadow for A15706573	1,741,652	13,436	1,315,589	439,499	201812	N/A	5/29/2019	439,499	-	-	439,499
135		A16806538	A16806538: ROW: Memphis to Estelline	743,488	129,145	1,219,954	(347,321)	201812	N/A	12/3/2018	(347,321)	-	-	(347,321)
136		P16082501	P16082501: SHADOW for P16082001	1,508,014	24,867	1,149,711	383,170	201812	N/A	11/16/2018	383,170	-	-	383,170
137		B194LASRE	B194LASRE T/SW/NonSpecificWorkStation-LA	229,172	1,054,193	1,076,005	207,360	201812	201901	Blanket	207,360	694,533	837,136	64,757
138		DP14S03C0	DP14S03C0: SEP/TX/Morton Saline Sub T-Lin	580,641	338,185	958,400	(39,574)	201812	N/A	10/1/2018	(39,574)	-	-	(39,574)
139		P14139005	P14139005: LINWOOD-S SHREVEPORT ROW	-	723,328	723,328	-	201806	N/A	5/10/2018	-	-	-	-
140		A15706007	A15706007: cedarville tap	-	13,998	647,180	(633,182)	201812	N/A	12/1/2018	(633,182)	-	-	(633,182)
141		B194ARTRE	B194ARTRE: T/SW/Trans Region Tools	-	551,201	562,346	(11,145)	201812	201901	Blanket	(11,145)	597,587	652,456	(66,014)
142		A13216A46	A13216A46: Trichel-Arsenal Hill TelLegFib	757,600	1,050	525,575	233,075	201812	N/A	12/12/2018	233,075	-	-	233,075

Southwestern Electric Power Company
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Test Year Ending December 31, 2018
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SCHEDULE B-8

Explanation: A schedule of individual construction projects, grouped by function, that support the test year amount of CWIP included on Schedule B-3 and proposed additions to Gross Plant on Schedule B-2. Subtotals should be included for each function. All projects under $500,000 may be grouped by function by Major Gas and Electric utilities and projects under $250,000 may be grouped by function by Non-Major utilities.

Line No.	Function	(1) Project Identifying Number	(2) Description of Construction	(3) Rounded Historical CWIP as of 7/31/2018 (A)	(4) 2018 Additions	(5) 2018 CWIP Completed	(5a) CWIP Balance At end of Test Year 12/31/2018	(6) Date of Last Construction Activity	(6a) Projected Start Date of Projects to Started in Proforma Year	(6b) Projected Date of Completion and Inclusion in Gross Plant	(7) CWIP Balance at Beginning Proforma Year 2019	(8) 2019 Additions	(9) 2019 CWIP Completed	(10) Projected Final Cost of Completed Projects not included in Col. 9 12/31/2019
143		A15713096	A15713096: East Rogers-Shipe Rd TelModFib	90,168	1,706	78,880	12,994	201812	201901	12/4/2019	12,994	944,521	944,521	12,994
144		A15713093	A15713093: Dyess -East Rogers TelModFib	57,315	1,263	58,427	151	201812	201901	11/8/2019	151	683,953	683,953	151
145		A15713102	A15713102: Knox Lee - NW Henderson TelMod	34,876	773	35,740	(91)	201812	201901	12/16/2019	(91)	780,946	780,946	(91)
146		O18SCO001	O18SCO001: CAMS Applications - SPP	-	17,399	17,862	(463)	201812	201901	6/30/2020	(463)	600,070	502,579	97,028
147		A16806038	A16806038: Arsenal Hill-Lieberman t-line	1,708	495,138	-	496,846	201812	201901	1/1/2020	496,846	371,006	867,710	142
148		A15706623	A15706623: Vernon Main CB 122	229,003	204,507	-	433,510	201812	201901	6/26/2019	433,510	456,694	959,681	(69,477)
149		P16105003	P16105003: Cass Tap - TLine	66,755	360,999	-	427,754	201812	201901	3/22/2019	427,754	250,781	1,258,913	(580,378)
150		P15127011	P15127011: Stonewall-Remote End	245,628	174,332	-	419,960	201812	201901	5/31/2019	419,960	382,888	753,388	49,460
151		A16806526	A16806526: Cookville Tap- Cookville Rehab	403,596	9,886	-	413,482	201812	201901	5/31/2019	413,482	1,496,455	1,900,315	9,622
152		P16105011	P16105011: Anderson Creek - Remote End	137,667	261,164	-	398,831	201812	201901	3/1/2019	398,831	403,701	929,530	(126,998)
153		P16105005	P16105005: West Atlanta - Remote End	128,999	251,646	-	380,645	201812	201901	3/22/2019	380,645	335,252	823,145	(107,248)
154		P16105012	P16105012: North New Boston - Remote End	127,674	222,098	-	349,772	201812	201901	2/22/2019	349,772	353,999	812,214	(108,443)
155		P16105009	P16105009: Munz City - TLine	32,168	268,669	-	300,837	201812	201901	4/12/2019	300,837	222,257	1,234,567	(711,473)
156		A13216A22	A13216A22: Fort Humbug - Telecom Pilot Wi	3,448	294,372	-	297,820	201812	201901	10/21/2019	297,820	387,861	710,162	(24,481)
157		TA1880648	TA1880648: SWEPCo T-Line Emerging Work	-	246,338	-	246,338	201812	201901	Contingency	246,338	765,080	1,112,793	(101,375)
158		P15127009	P15127009: Summer Grove-Station	64,831	148,728	-	213,559	201812	201901	12/31/2019	213,559	448,724	713,681	(51,398)
159		P15127004	P15127004: Leaside Way-TLine2	50,852	153,737	-	204,589	201812	201901	5/31/2019	204,589	444,012	759,615	(111,014)
160		A16806021	A16806021: Bann-N New Boston Rebuild	83,959	9,046	-	93,005	201812	201901	11/13/2020	93,005	1,873,929	2,225,558	(258,624)
161		A15706C29	A15706C29: SEP-IPCDomino-WestAtlanta-RHB	-	-	-	-	N/A	201907	12/31/2019	-	1,114,249	1,114,250	(1)
162		A16806005	A16806005: Greenland-VBI North-VBI retire	-	-	-	-	N/A	201901	11/30/2018	-	1,585,774	1,585,774	-
163		ESTBLK194	ESTBLK194: T/SW/Capital Blankt SWEPCo	-	-	-	-	N/A	201901	Blanket	-	3,908,296	3,580,471	327,825
164		TA1692411	TA1692411: SWEPCo Major Eq/Spares	-	-	-	-	N/A	201907	6/1/2020	-	2,789,462	2,321,548	467,914
165		TBB194001	TBB194001: SpringdaleServiceCenter	-	-	-	-	N/A	201901	6/1/2020	-	2,450,008	2,450,004	4
166		A15713107	A15713107: Jefferson SW - Str 24 TelModF	57,383	1,274	58,807	(150)	201808	201901	4/21/2021	(150)	1,769,122	1,769,122	(150)
167		ESTCOR194	ESTCOR194: T/SW/TBCORP194 Estimate	-	-	-	-	N/A	201901	Blanket	-	14,056,370	12,874,921	1,181,449
168		Less than $500k		24,344,934	(11,750,534)	(11,398,534)	23,992,934	Various	Various	Various	23,992,934	81,635,097	16,777,322	88,850,709
169	Transmission Plant Sum			118,449,083	41,758,216	45,187,951	115,019,348				115,019,348	158,406,349	169,041,421	104,384,276
170	Distribution Plant	A12102601	A12102601 D/SW/PurchNewMobile SW-15-TE	2,612,041	-	-	2,612,041	201812	N/A	6/30/2017	2,612,041	-	-	2,612,041
171		TA1880649	TA1880649: SWEPCo D-Station Emerging Work	-	1,727,030	-	1,727,030	201812	201901	Blanket	1,727,030	1,063,753	3,472,693	(681,910)
172		DCTSUVLSW	DCTSUVLSW SWEP CATS Monthly Unvouch I	1,675,971	-	-	1,675,971	N/A	N/A	UVL	1,675,971	-	-	1,675,971
173		CORPR159D	CORPR159D: Corporate Reserve - SWEPCO Di	-	7,300,564	5,837,976	1,462,588	N/A	201901	12/31/2028	1,462,588	11,036	1,473,626	(2)
174		DN15S01F0	DN15S01F0 SEP/LAShrvpt Netwk Remed	1,068,792	1,326,324	1,333,130	1,061,986	201812	201901	12/31/2018	1,061,986	1,970	263,441	800,515
175		EDN100522	EDN100522: SEP LA Cpp Capacity Work	-	1,155,888	385,296	770,592	201812	201901	Budget Only	770,592	4,317,767	4,725,898	362,461
176		B161TXSRE	B161TXSRE D/SW/Non-Specific Work Station I	687,245	99,450	79,555	707,140	201812	201901	Blanket	707,140	1,033,840	968,344	772,636
177		000024654	000024654 SWEPCO-D General Plt Cap Blkt	649,212	-	-	649,212	201807	N/A	Blanket	649,212	-	-	649,212
178		000005644	000005644: Ds-SEP-La-AI Pole Replacement	659,527	2,715,823	2,727,024	648,326	201812	201901	Blanket	648,326	6,115,598	6,176,291	587,633
179		CORPR161D	CORPR161D: Corporate Reserve-SWEPCO TX I	-	2,771,678	2,216,403	555,275	N/A	201901	12/31/2028	555,275	4,190	559,466	(1)
180		DP14S03B0	DP14S03B0: SEP/TX/Morton Saline Sub D-Sta	5,354,003	2,096,770	7,217,885	232,888	201812	N/A	10/1/2018	232,888	-	-	232,888
181		DR14S02E2	DR14S02E2 SEP/LA/Network Monitor Design	4,068,375	533,437	5,945,243	(1,343,431)	N/A	N/A	10/31/2018	(1,343,431)	-	-	(1,343,431)
182		EON100342	EON100342: Line Transformer/Swepco/Ark	91,058	3,782,604	3,800,030	73,632	201812	201901	Blanket	73,632	9,549,331	9,511,079	111,884
183		EON102626	EON102626: Ds/Septx/Line Transformer	124,143	2,681,877	2,690,507	115,513	201812	201901	Blanket	115,513	6,912,043	6,873,642	153,914
184		EDN102209	EDN102209: Ds-Septx-Ai Pole Replacement	340,637	2,521,623	2,525,822	336,438	201812	201901	Blanket	336,438	5,547,482	5,489,934	393,986
185		000025577	000025577: STATION WORK - TEXAS	-	1,871,571	1,873,660	(2,089)	201812	201901	Budget Only	(2,089)	3,046,456	3,043,086	1,281
186		000025578	000025578: STATION WORK - LOUISIANA	-	1,709,928	1,716,213	(6,285)	201812	201901	Budget Only	(6,285)	2,835,784	2,824,549	4,950
187		DP17S06B0	DP17S06B0: NEW BRUSH CREEK - D STATION	12,405	1,672,960	1,681,218	4,147	201812	201901	12/1/2018	4,147	2,483	332,281	(325,651)
188		EDN100064	EDN100064: Ds-Sep-Ark-Ai Pole Replacement	176,109	1,534,868	1,539,497	171,480	201812	201901	Blanket	171,480	3,442,869	3,657,153	(42,804)
189		HORATIOAR	HORATIOAR: SWP Horatio Rebuild Prjt	140,133	960,092	1,437,544	(337,319)	201812	N/A	Blanket	(337,319)	-	-	(337,319)
190		EDN102199	EDN102199: Ds/Septx/C&I New	126,170	1,403,814	1,404,133	125,851	201812	201901	Blanket	125,851	4,269,860	4,194,094	201,617
191		000025579	000025579: STATION WORK - ARKANSAS	-	1,189,514	1,193,887	(4,373)	201812	201901	Budget Only	(4,373)	1,963,235	1,956,587	2,275
192		000005608	000005608: Ds/SWEP/La/Cs-New Customers	179,516	1,090,965	1,093,791	176,690	201812	201901	Blanket	176,690	3,573,168	3,492,362	257,496
193		000025582	000025582: DA Distribution Station - TX	-	1,024,024	1,025,166	(1,142)	201812	201901	Blanket	(1,142)	3,187,148	3,127,751	58,255
194		DR18S01A8	DR18S01A8 DA Distribution Line - Texas	-	1,024,024	1,025,166	(1,142)	201812	201901	Blanket	(1,142)	1,530,371	1,607,395	(78,166)
195		DR18S01A6	DR18S01A6: DA Distribution Line - LA	168,667	1,016,935	1,020,673	164,929	201812	201901	Blanket	164,929	1,530,088	1,604,604	90,413
196		DR18S01A7	DR18S01A7 DA Distribution Line - Ark	4,224	1,016,935	1,020,673	486	201812	201901	Blanket	486	1,530,088	1,604,604	(74,030)
197		000025580	000025580: DA Distibution Station - LA	-	1,016,935	1,020,673	(3,738)	201812	201901	Blanket	(3,738)	3,186,582	3,124,640	58,204
198		000025581	000025581: DA Distribution Station - Ark	-	1,016,935	1,020,673	(3,738)	201812	201901	Blanket	(3,738)	3,186,582	3,124,640	58,204
199		EDN100476	EDN100476: Customer Meter/Swepco/Ark	69,199	927,257	931,345	65,111	201812	201901	Blanket	65,111	1,719,954	1,761,551	23,514
200		000007824	000007824: SEP/Small Local Asset Imp-La	80,158	843,000	843,185	79,973	201812	201901	Blanket	79,973	2,624,631	2,572,668	131,936
201		EDN102197	EDN102197: Ds/Septx/Residential New	288,649	837,667	837,983	288,333	201212	201901	Blanket	288,333	3,226,133	3,123,884	390,582
202		000005621	000005621: Ds/SWEP/La-C&I New	114,310	768,086	769,498	112,898	201812	201901	Blanket	112,898	2,765,049	2,687,532	190,415
203		000007606	000007606: SEPTX-Failed Equip No Outage	103,076	713,697	714,571	102,202	201812	201901	Blanket	102,202	2,246,975	2,202,296	146,881
204		000007826	000007826: SEP/Small Local Asset Imp-ARK	102,542	640,347	641,863	101,026	201812	201901	Blanket	101,026	1,822,063	1,797,608	125,481
205		000018434	000018434: Major Storm Reserve - SWEPCo	-	621,396	622,684	(1,288)	201812	201901	Budget Only	(1,288)	3,426,047	3,266,862	157,897
206		DR18S01A5	DR18S01A5: Overhead Renewal Project - TX	-	598,903	599,572	(669)	201812	201901	12/31/2022	(669)	1,957,138	1,914,732	41,737
207		DR18S01A3	DR18S01A3: Overhead Renewal Project - LA	-	594,755	596,944	(2,189)	201812	201901	12/31/2022	(2,189)	1,956,791	1,912,895	41,707
208		DR18S01A4	DR18S01A4: Overhead Renewal Project - Ark	-	594,755	596,944	(2,189)	201812	201901	12/31/2022	(2,189)	1,956,791	1,912,895	41,707
209		TA1571312	TA1571312: D/SW/AR Telecom Modernization	-	606,764	568,209	38,555	201812	201901	Budget Only	38,555	81,405	187,637	(67,677)
210		EDN102625	EDN102625: Ds/Septx/Meter Blanket	8,677	541,665	543,033	7,309	201812	201901	Blanket	7,309	1,012,450	1,036,344	(16,585)
211		000009176	000009176: Forestry SEP LA D Base R W	15,478	582,089	529,259	68,308	201812	201901	12/31/2018	68,308	1,133,658	1,193,663	8,303
212		000020161	000020161: SWE/LA/Cust Svc - Res - OH/UG	7,667	490,435	490,110	7,992	201812	201901	Blanket	7,992	1,522,818	1,492,738	38,072
213		000007604	000007604: SEPLA-Failed Equip No Outage	12,702	463,042	464,727	11,017	201812	201901	Blanket	11,017	1,363,589	1,342,341	32,265
214		EDN100165	EDN100165: SEP La Svc Restor NonMjr Ev	8,044	420,714	421,120	7,638	201812	201901	Blanket	7,638	1,428,636	1,392,946	43,328
215		EDN100037	EDN100037: Cs/Sep/Ark-C&I New	89,979	420,863	419,544	91,298	201812	201901	Blanket	91,298	1,288,392	1,265,030	114,660

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216		EDN100023	EDN100023: Ds/Sep/Ark/Residential New	42,609	416,640	417,499	41,750	201812	201901	Blanket	41,750	1,235,771	1,215,670	61,851
217		000007585	000007585: SEPLA-Cable Repl Failure	46,480	410,711	411,966	45,225	201812	201901	Blanket	45,225	1,166,887	1,151,501	60,611
218		000007825	000007825: SEP-Small Local Asset Imp-TX	57,387	376,245	376,234	57,398	201812	201901	Blanket	57,398	1,084,429	1,069,159	72,668
219		000007589	000007589: SEPTX-UG Cable Repl Failure	27,549	361,199	361,836	26,912	201812	201901	Blanket	26,912	957,912	950,483	34,341
220		000007587	000007587: SEPAR-Cable Repl Failure	1,932	288,647	289,808	771	201812	201901	Blanket	771	759,384	753,836	6,319
221		EDN100093	EDN100093: Ds/Sep/Ark-Public Relocation	20,403	277,036	277,183	20,256	201812	201901	Blanket	20,256	882,643	864,000	38,899
222		000014419	000014419: SEP/DS/Distr Line Tools	-	273,845	275,152	(1,307)	201812	201901	Blanket	(1,307)	557,332	565,596	(9,571)
223		000005695	000005695: Ds/SEP/La-Public Projects	267,594	270,122	270,927	266,789	201812	201901	Blanket	266,789	838,286	822,114	282,961
224		EDN102200	EDN102200: Ds/Septx/C&I Upgrade	93,351	264,356	264,193	93,514	201812	201901	Blanket	93,514	912,113	888,933	116,694
225		000004743	000004743: SWEP-TSectionalizing Program	112,662	242,198	242,857	112,003	201812	201901	Blanket	112,003	669,578	662,258	119,323
226		000005679	000005679 Ds-SEP-La-AI Ckt Inspections/Repl	42,013	206,206	207,002	41,217	201812	201901	Blanket	41,217	582,555	575,142	48,630
227		EDN102215	EDN102215 Ds-Septx-Ai Ckt Inspections/Repla	126,675	204,150	204,044	126,781	201812	201901	Blanket	126,781	568,265	561,997	133,049
228		000007605	000007605: SEPAR-Failed Equip No Outage	26,464	197,161	197,866	25,759	201812	201901	Blanket	25,759	531,058	526,155	30,662
229		EDN103232	EDN103232: SEPTX Svc Restoration NonMjr	15,192	197,265	197,505	14,952	201812	201901	Blanket	14,952	617,721	605,665	27,008
230		DR18S01A0	DR18S01A0 Fault Sensors - Louisiana	414	196,273	196,992	(305)	201812	201901	Blanket	(305)	3,889,469	3,607,779	281,385
231		000005723	000005723: SEP-La-Damage Claims Reimb	33,172	181,413	181,686	32,899	201812	201901	Blanket	32,899	548,797	539,050	42,646
232		EDN100068	EDN100068: Ds-Sep-Ark-Ai Small Wire Repl	1,973	181,489	181,498	1,964	201812	201901	Blanket	1,964	626,969	610,636	18,297
233		000014972	000014972: SWE Tx Cpp Capacity Work	-	389	393	(4)	201812	201901	Budget Only	(4)	4,155,636	3,807,865	347,767
234		IBCRESRVE	IBCRESRVE: Inf Bus Con Reserve	-	333,585	-	333,585	201812	201901	Contingency	333,585	1,654	572,574	(237,335)
235		A13216A16	A13216A16: Whitehurst -Telecom Pilot Wire	52,052	215,038	-	267,090	201812	201901	9/27/2019	267,090	263,414	539,078	(8,574)
236		000014971	000014971: SEP AR Cpp Capacity Work	-	-	-	-	N/A	201901	Budget Only	-	2,573,235	2,356,701	216,534
237		DR18LABOR	DR18LABOR: Modernization Project (Labor)	-	-	-	-	N/A	201901	Blanket	-	1,568,509	1,438,659	129,850
238		ESTBLK159	ESTBLK159: D/SW/Co Tool Blanket	-	-	-	-	N/A	201901	Blanket	-	1,336,658	1,226,550	110,108
239		SMRTCRC	SMRTCRC: Smart Circuit	-	154,412	-	154,412	N/A	201901	Budget Only	154,412	387,959	-	542,371
240		EDN102198	EDN102198: Ds/Septx/Residential Upgrade	3,056	206,775	206,834	2,997	201812	201901	Blanket	2,997	858,342	828,209	33,130
241		Less than $500k		6,754,837	3,334,114	766,553	9,322,398	Various	Various	Various	9,322,398	10,065,430	9,726,674	9,661,154
242	Distribution Plantc Sum			26,764,524	65,717,272	68,950,457	23,531,339				23,531,339	137,014,250	140,738,066	19,807,523
243	General Plant	ITCW15903	ITCW15903 SWEPCO Next Gen Radio Sys	2,499,920	1,416,212	-	3,916,132	201812	201901	12/31/2021	3,916,132	6,516,298	-	10,432,430
244		000021554	000021554 SWEPCO DHLC/Pirkey Land Acq	3,190,058	-	-	3,190,058	201812	N/A	N/A	3,190,058	-	-	3,190,058
245		ITCW16103	ITCW16103 SWEPCO Next Gen Radio Sys	2,853,103	-	-	2,853,103	N/A	201901	12/31/2021	2,853,103	-	-	2,853,103
246		DR14S02E2	DR14S02E2 SEP/LA/Network Monitor Design	1,516,293	-	-	1,516,293	N/A	N/A	10/31/2018	1,516,293	-	-	1,516,293
247		X00000324	X00000324 Administrative	1,346,362	-	-	1,346,362	N/A	N/A	Blanket	1,346,362	-	-	1,346,362
248		X00000296	X00000296 Administrative	964,954	-	-	964,954	201812	N/A	Blanket	964,954	-	-	964,954
249		000005708	000005708 Ds SEP La-Overheads	584,606	-	-	584,606	N/A	N/A	OVHD	584,606	-	-	584,606
250		X00000366	X00000366 Administrative	548,261	-	-	548,261	N/A	N/A	Blanket	548,261	-	-	548,261
251		ITCB15900	ITCB15900: SOUTHWESTERN ELEC PWR-DIS	501,794	191,657	192,916	500,535	201812	201901	Blanket	500,535	473,684	472,542	501,677
252		000025707	000025707: Mid South Tower Roof Repl	-	1,197,034	1,021,020	176,014	201812	201901	12/31/2018	176,014	1,326	177,341	(1)
253		000025384	000025384: Dolan IT Building	-	447,221	873,610	(426,389)	201812	201908	12/1/2018	(426,389)	233,496	233,496	(426,389)
254		000025251	000025251: 2018 General Plt Cap Blkt - SEP-D T	14,668	85,925	86,022	14,571	201812	201901	Blanket	14,571	1,117,014	1,042,074	89,511
255		000025252	000025252: 2018 Gen Plt Cap Blkt - SEP-G	13,456	-	-	13,456	201812	201901	Blanket	13,456	582,019	534,243	61,232
256		Less than $500k		3,643,399	1,267,338	596,582	4,314,155	Various	Various	Various	4,314,155	8,121,045	1,056,470	11,378,730
257	General Plant Sum			17,676,874	4,605,387	2,770,150	19,512,111				19,512,111	17,044,882	3,516,166	33,040,827
258	Grand Total			213,767,956	203,361,685	208,664,793	208,464,848				208,464,848	436,188,301	416,611,232	228,041,917

Definitions:

Blanket - Repetitive and predictable work charged and closed continuously throughout the calendar year.

Contingency - Funding for emerging work and/or non-controllable events, i.e., unexpected equipment failure.

Unvouchered Liability - Amount of material and service costs incurred, but not yet invoiced.

Budget Only - Funding for planned, but unidentified work. As projects are identified, funding is transferred from this project.

Note: Project details for the test year and pro-forma year with credit balance are due to variations in the forecast process actual balances are not negative and will updated as actuals are available.

Reclassed CWIP In-service at Pro-forma Year End	Test Year 12/31/2018 CWIP	Reclassified CWIP at Proforma Year End	Total CWIP Test Year End
Distribution	23,531,339	4,000,189	19,531,150
General	19,512,111	-	19,512,111
Intangible	11,912,206	7,584,352	4,327,854
Other Generation	14,246	-	14,246
Steam Generation	38,475,598	14,439,547	24,036,051
Transmission	115,019,348	16,184,668	98,834,680
	208,464,848	42,208,756	166,256,092

Recap Schedules
Schedule B-1
(A) Schedule B-3
(B) Schedule B-2

Supporting Schedules:
(a) E-17

Southwestern Electric Power Company
Schedule of Retirement Work In Progress
Test Year Ending December 31, 2018
Docket No. 19-008-U

Schedule B-9

Explanation: A schedule of individual retirement projects at the end of the test year and projected in the pro forma year, subtotaled by function. All projects under $500,000 may be grouped by function by Major Gas and electric utilities and projects under $250,000 may be grouped by function by Non-Major utilities. Provide details of the cost of removal and/or salvage.

Line No.	Function	(1) Project Identifying Number	(2) Description of Retirement	(3) (Rounded) Historical RWIP 7/31/2018	(4) Additions 2018	(5) RWIP Completed in Test Year 12/31/2018	(6) RWIP End of Test Year	(6a) Date Last Activity	(6b) Projected Start Date of Projects in Pro Forma Year	(6c) Projected Date of RWIP Project Completion	(7) Additions 2019 Pro Forma	(8) RWIP Completed in Pro Forma Year	(9) RWIP End of Pro Forma Year 12/31/2019
1	Other Generation Plant	Less than $500k		139,354	2,628	-	141,981	N/A	N/A	Blanket	7,792	-	149,773
2	Other Generation Plant Total			139,354	2,628	-	141,981				7,792	-	149,773
3	Steam Generation Plant	WLKCI2004	‹CI2004: U2 SH&RH Outlet BNK&HDR	692,657	25,094	717,751	-	201804	N/A	8/30/2018	-	-	-
4		Less than $500k		5,568,577	862,051	47,368	6,383,260	Various	Various	Various	397,069	35,239	6,745,090
5	Steam Generation Plant Total			6,261,234	887,145	765,119	6,383,260				397,069	35,239	6,745,090
6													
7													
8	Transmission Plant - Electric	Less than $500k		2,112,603	181,268	141,432	2,152,440	Various	Various	Various	199,987	81,872	2,270,555
9	Transmission Plant - Electric Total			2,112,603	181,268	141,432	2,152,440				199,987	81,872	2,270,555
10	Distribution Plant - Electric	EDN102209	EDN102209: Ds-Septx-Ai Pole Replace	541,068	19,603	10,550	550,121	201812	201901	Blanket	32,950	6,107	576,964
11		000005644	000005644: Ds-SEP-La-AI Pole Replac	478,973	17,353	9,339	486,987	201812	201901	Blanket	29,169	5,406	510,750
12		Less than $500k		2,115,665	89,271	47,211	2,157,725	Various	Various	Various	152,051	27,330	2,282,446
13	Distribution Plant - Electric Total			3,135,706	126,227	67,100	3,194,833				214,170	38,843	3,370,160
14	General Plant	Less than $500k		699,862	17,882	5,559	712,185	Various	Various	Various	39,777	3,218	748,745
15	General Plant Total			699,862	17,882	5,559	712,185				39,777	3,218	748,745
16	Grand Total (a)			12,348,758	1,215,151	979,210	12,584,699				858,796.00	159,172.00	13,284,323

Definitions:

Blanket - Repetitive and predictable work charged and closed continuously throughout the calendar year.

Supporting Schedules:
(a) E-17B

Recap Schedules

Southwestern Electric Power Company
Acquisition Adjustment
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE B-10

Explanation: Schedule showing all acquisition adjustments and the related annual amortization amounts.

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				Acquisition Adjustment			Accum. Amortization			Annual Amortization		
Line No.	Account Number	Description	Acquisition Date	Actual Amount per Trial Balance at End of Historical Portion of Test Year (a)	Adjustments for Projected Portion of Test Year*	6/30/2018 Total Test Year (Col. 5 + Col. 6)	Actual Amount per Trial Balance at End of Historical Portion of Test Year (a)	Adjustments for Projected Portion of Test Year*	Total Test Year (Col. 8 + Col. 9)	Actual Amount per Trial Balance at End of Historical Portion of Test Year (a)	Adjustments for Projected Portion of Test Year*	Total Test Year (Col. 11 + Col. 12)
1	114 / 115	Distribution facilities purchased - BREMCO / Haughton LA	6/15/1905	18,043,976	-	18,043,976	(18,043,976)	-	(18,043,976)	-	-	-
2		Total		18,043,976	-	18,043,976	(18,043,976)	-	(18,043,976)	-	-	-

Supporting Schedules and Workpapers:
(a) E-17

Recap Schedules:
(A) Schedule B-3
(B) Schedule C-1
Schedule B-2

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Southwestern Electric Power Company
Index C-Work Papers
Test Year Ending December 31, 2018
Docket No. 19-008-U

Southwestern Electric Power Company **SCHEDULE C-1**
Test Year and Pro Forma Year Statement of Utility Operating Income
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing test year and pro forma year statement of utility operating income

(1) Line No.	(2) Description	(3) FERC Accts	(4) Amount at end of Test Year (a)	(5) Adjustments (b)	(6) Pro Forma Year (A)
	Operating Revenue:				
	Retail & Wholesale:				
1	Operating Revenue: by rate class				-
2	Residential	440	668,241,696	(265,279,741)	402,961,955
3	Commercial & Industrial	442	867,920,278	(365,080,827)	502,839,451
4	Street Light	444	8,757,490	(33,079,900)	(24,322,410)
5	Public Authorities	445	-		-
6	Munis, COOP's, & Off System	447	62,443,742	(139,072,407)	(76,628,665)
7	Provision for Refund	449.1	(63,427,415)	63,427,415	-
8	Total System		1,543,935,791		804,850,331
9	Sales for Resale	447	161,165,189		161,165,189
10	Other Operating Revenue	450, 451, 454, 456	126,103,200	8,246,562	134,349,762
11	**Total Operating Revenue**		**1,831,204,180**	**(730,838,898)**	**1,100,365,282**
	Operating Expenses:				
12	Fuel Expense	501,547	510,992,566	(491,603,950)	19,388,616
13	Purchased Power	555	180,176,090	(171,126,607)	9,049,483
14	Production and Other Production	Various	154,941,476	(23,726,776)	131,214,700
15	Transmission	560-573	135,414,197	9,768,873	145,183,070
16	Regional Market Expense	575.7	1,514,936	-	1,514,936
17	Distribution	580-598	83,737,724	2,866,977	86,604,701
18	Customer Service & Informational	907-910	21,330,115	(18,204,443)	3,125,672
19	Sales	911-913, 916	166,554	(22,323)	144,231
20	Customer Accounts	901-905	18,314,724	4,011,728	22,326,452
21	Administrative & General	920-935	78,966,630	536,185	79,502,815
22	Depreciation & Amortization	403,404,406	239,098,918	(5,254,252)	233,844,665
23	Regulatory Debits	407	2,601,307	(1,713,791)	887,516
24	Taxes Other Than Income Taxes	408.1	102,213,260	(974,841)	101,238,419
25	Federal Income Taxes	409.1	22,913,183	(2,093,009)	20,820,174
26	State Income Taxes	409.1	4,518,352	(1,384,442)	3,133,910
27	Deferred Federal Income Taxes, net	410.1	777,092,760	(6,470,505)	770,622,255
28	Deferred Income Taxes- Cr	411.1	(783,738,050)		(783,738,050)
29	Investment Tax Credit, net	411.4	(1,244,396)	857,639	(386,757)
30	Gains from Disposition of Allowance	411.8	619,127	-	619,127
31	Accretion	411.10	2,558,193	-	2,558,193
32	**Total Operating Expense**		1,552,187,666	(704,533,537)	847,654,128
33	**Net Utility Operating Income**		279,016,514	(26,305,361)	252,711,154

Supporting Schedules:
(a) C-3
(b) Schedule C-2

Recap Schedules:
(A) G-3

Note: See functional O&M by detailed subaccount on Schedule C-2

Southwestern Electric Power Company
Adjustments to Test Year Statement of Utility Operating Income
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing adjustments to the test year statement of utility operating income by account and by adjustment. Do not include adjustments for proposed rate changes on this schedule. Adjustments for proposed rates changes should be shown on Schedule H-1.

		Annualized Payroll	Incentive Compensation	FICA Expense	Credit Line Fees	Rate Case Expense	EE Removal	Fuel and PP Removal	Reg Amort	Aviation	AEPSC Incentives	AEPSC Payroll
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
FERC ACCT.NO.	DESCRIPTION	Adj. No. IS-1	Adj. No. IS-2	Adj. No. IS-3	Adj. No. IS-4	Adj. No. IS-5	Adj. No. IS-6	Adj. No. IS-7	Adj. No. IS-8	Adj. No. IS-9	Adj. No. IS-10	Adj. No. IS-11
FERC	**FERC Title** **Account**											
4400	**Residential Sales**											
4400001	Residential Sales-W/Space Htg											
4400002	Residential Sales-W/O Space Ht											
4400005	Residential Fuel Rev											
4400006	Residential O/U Fuel Rev											
	4400 Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
4420	**Commercial & Industrial Sales**											
4420001	Commercial Sales											
4420002	Industrial Sales (Excl Mines)											
4420006	Sales to Pub Auth - Schools											
4420007	Sales to Pub Auth - Ex Schools											
4420013	Commercial Fuel Rev											
4420014	Commercial O/U Fuel Rev											
4420016	Industrial Fuel Rev											
4420017	Industrial O/U Fuel Rev											
	4420 Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
4440	**Public Street/Highway Lighting**											
4440000	Public Street/Highway Lighting											
4440002	Public St & Hwy Light Fuel Rev											
4440003	Pb St & Hwy Light O/U Fuel Rev											
	4440 Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
4470	**Sales for Resale**											
4470001	Sales for Resale - Assoc Cos											
4470002	Sales for Resale - NonAssoc											
4470006	Sales for Resale-Bookout Sales											
4470010	Sales for Resale-Bookout Purch											
4470027	Whsal/Muni/Pb Ath Fuel Rev											
4470028	Sale/Resale - NA - Fuel Rev											
4470032	Capacity Revenue - Affiliated											
4470033	Whsal/Muni/Pub Auth Base Rev											
4470035	Sls for Rsl - Fuel Rev - Assoc											
4470036	Sales for Resale- Fuel - ERCOT											
4470074	Sale for Resale-Aff-Trnf Price											
4470081	Financial Spark Gas - Realized											
4470082	Financial Electric Realized											
4470131	Non-Trading Bookout Purch-OSS											
4470136	SPP Rev Neutrality Ded-Sales											
4470150	Transm. Rev.-Dedic. Whlsl/Muni											
4470175	OSS Sharing Reclass - Retail											
4470176	OSS Sharing Reclass-Reduction											
4470219	Merchant Fuel Revenue											
4470223	Merchant Sales Margin											
4470320	SPP Net Regulation OSS											
4470321	SPP Net Spinning Reserve OSS											
4470324	SPP Net Supp Reserve OSS											
4470326	SPP Net Marginal Losses OSS											
4470328	SPP Net Make Whole Payment OSS											
4470332	SPP Congestion Costs OSS											

Supporting Schedules:
(a) WP C 2-1 - WP C 2-26

Recap Schedules:
(A) Schedule C-1

Southwestern Electric Power Company
Adjustments to Test Year Statement of Utility Operating Income
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing adjustments to the test year statement of utility operating income by account and by adjustment. Do not include adjustments for proposed rate changes on this schedule. Adjustments for proposed rates changes should be shown on Schedule H-1.

		Annualized Payroll	Incentive Compensation	FICA Expense	Credit Line Fees	Rate Case Expense	EE Removal	Fuel and PP Removal	Reg Amort	Aviation	AEPSC Incentives	AEPSC Payroll
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
FERC ACCT.NO.	DESCRIPTION	Adj. No. IS-1	Adj. No. IS-2	Adj. No. IS-3	Adj. No. IS-4	Adj. No. IS-5	Adj. No. IS-6	Adj. No. IS-7	Adj. No. IS-8	Adj. No. IS-9	Adj. No. IS-10	Adj. No. IS-11
	4470 Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
4491	**Provision for Rate Refunds**											
4491002	Prov Rate Refund-Nonaffiliated											
4491003	Prov Rate Refund - Retail											
4491004	Prov Rate Refund - Affiliated											
4491018	Prov Rate Refund - Tax Reform											
4491019	Prov Rate Refund-Exces Protect											
	4491 Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
4500	**Forfeited Discounts**											
4500000	Forfeited Discounts											
	4500 Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
4510	**Misc Service Revenues**											
4510001	Misc Service Rev - Nonaffil											
	4510 Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
4540	**Rent From Electric Property**											
4540001	Rent From Elect Property - Af											
4540002	Rent From Elect Property-NAC											
4540004	Rent From Elect Prop-ABD-Nonaf											
4540005	Rent from Elec Prop-Pole Attch											
	4540 Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
4560	**Other Electric Revenues**											
4560010	Oth Elect Rev - Royalties											
4560012	Oth Elect Rev - Nonaffiliated											
4560013	Oth Elect Rev-Trans-Nonaffil											
4560015	Other Electric Revenues - ABD											
4560025	Plant Operations O/H Revenues											
4560041	Miscellaneous Revenue-NonAffil								(409,254)			
4560043	Oth Elec Rv-Trn-Aff-Trnf Price											
4560102	Oth Elect Rev-Trans-ERCOT area											
	4560 Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(409,254)**	**0**	**0**	**0**
4561	**Other Electric Revenues**											
4561008	SPP Non-Affil. Base Fundng Rev											
4561009	SPP Affil. Base Funding Cost											
4561010	SPP Affl. Base Funding Rev											
4561011	SPP Pt to Pt Trans Serv Rev											
4561012	SPP Direct Assignment											
4561013	SPP Affiliated NITS Revenue											
4561014	SPP Ancillary Services											
4561015	SPP Ancillary Schedule 1											
4561016	SPP Affiliated Trans NITS Cost											
4561017	Oth Elect Revenues - Ancillary											
4561019	Oth Elec Rev Trans Non Aff											
4561020	Oth Elec Rev-Trans-Aff-SPP											
4561021	SPP NITS											
4561038	SPP Pt to Pt Trans Affil Cost											
4561039	SPP Pt to Pt Trans Affil Rev											
4561040	Affil. SPPAncillary Sch.1 Cost											
4561041	Affil. SPPAncillary Sch. 1 Rev											

Supporting Schedules:
(a) WP C 2-1 - WP C 2-26

Recap Schedules:
(A) Schedule C-1

Schedule C-2

Southwestern Electric Power Company
Adjustments to Test Year Statement of Utility Operating Income
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing adjustments to the test year statement of utility operating income by account and by adjustment. Do not include adjustments for proposed rate changes on this schedule. Adjustments for proposed rates changes should be shown on Schedule H-1.

		Annualized Payroll	Incentive Compensation	FICA Expense	Credit Line Fees	Rate Case Expense	EE Removal	Fuel and PP Removal	Reg Amort	Aviation	AEPSC Incentives	AEPSC Payroll
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
FERC ACCT.NO.	DESCRIPTION	Adj. No. IS-1	Adj. No. IS-2	Adj. No. IS-3	Adj. No. IS-4	Adj. No. IS-5	Adj. No. IS-6	Adj. No. IS-7	Adj. No. IS-8	Adj. No. IS-9	Adj. No. IS-10	Adj. No. IS-11
4561042	SPP Base Funding Contra											
4561065	Provision RTO Rev-NonAff											
	4561 Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	TOTAL REVENUES	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(409,254)**	**0**	**0**	**0**
	Production Operations											
5000	Oper Supervision & Engineering	46,026	(89,130)							(212,729)	(247,327)	43,930
5010	Fuel	42,018	(107,095)					(472,530,027)			(18,188)	14,164
5020	Steam Expenses	56,922	(148,007)					(4,136,116)			(2,464)	23,258
5050	Electric Expenses	49,040	(172,718)								(22)	5,580
5060	Misc Steam Power Expenses	86,910	(184,441)						(83,182)		415,008	(5,935)
5070	Rents											
5080	Operations - Supplies and Expenses											
5090	Allowance Consumption SO2							(29,861)				
	Total	**280,916**	**(701,391)**	**0**	**0**	**0**	**0**	**(476,696,004)**	**(83,182)**	**(212,729)**	**147,007**	**80,997**
	Production Maintenance											
5100	Maint Supv & Engineering	26,066	(39,081)								(24,546)	21,195
5110	Maintenance of Structures	5,335	(13,819)								(2,951)	184,660
5120	Maintenance of Boiler Plant	159,778	(401,425)								(21,377)	(256,534)
5130	Maintenance of Electric Plant	10,627	(26,950)								(4,423)	110,155
5140	Maintenance of Misc Steam Plt	8,615	(24,455)								(3,303)	35,922
	Total	**210,421**	**(505,730)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(56,600)**	**95,398**
	Other Power Generation Operations											
5470	Fuel							(19,001,320)				
5460 & 54	Generation Expenses	4,278	(8,361)									
	Total	**4,278**	**(8,361)**	**0**	**0**	**0**	**0**	**(19,001,320)**	**0**	**0**	**0**	**0**
	Other Power Generation Maintenance											
5530	Maintenance of Generating Plt	2,298	(4,842)								(107)	3,115
5540	Maint of Misc Oth Pwr Gneratn											
	Total	**2,298**	**(4,842)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(107)**	**3,115**
	Other Power Supply Expenses											
5550	Purchased Power							(171,126,607)				
5560	Sys Control & Load Dispatching										(42,645)	151,136
5570	Other Expenses									(6,939)	(74,344)	223,169
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**(171,126,607)**	**0**	**(6,939)**	**(116,989)**	**374,305**
	Transmission Operations											
5600	Oper Supervision & Engineering	11,608	(21,798)							(38,584)	(97,158)	339,319
5611	Load Dispatching		(5,445)								0	27
5612	Load Dispatching	5,476	(184)								(15,289)	(140,894)
5613	Load Dispatching											
5614	Load Dispatching											
5615	Load Dispatching										(2,364)	(17,987)
5616	Load Dispatching										(9)	15
5618	Load Dispatching											
5620	Station Expenses	1,391	(3,634)								(185)	373
5630	Overhead Line Expenses	767	(1,361)								(152)	3,583

Supporting Schedules:
(a) WP C 2-1 - WP C 2-26

Recap Schedules:
(A) Schedule C-1

Southwestern Electric Power Company
Adjustments to Test Year Statement of Utility Operating Income
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing adjustments to the test year statement of utility operating income by account and by adjustment. Do not include adjustments for proposed rate changes on this schedule. Adjustments for proposed rates changes should be shown on Schedule H-1.

		Annualized Payroll	Incentive Compensation	FICA Expense	Credit Line Fees	Rate Case Expense	EE Removal	Fuel and PP Removal	Reg Amort	Aviation	AEPSC Incentives	AEPSC Payroll
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
FERC ACCT.NO.	DESCRIPTION	Adj. No. IS-1	Adj. No. IS-2	Adj. No. IS-3	Adj. No. IS-4	Adj. No. IS-5	Adj. No. IS-6	Adj. No. IS-7	Adj. No. IS-8	Adj. No. IS-9	Adj. No. IS-10	Adj. No. IS-11
5640	Underground Line Expenses											
5650	Trnsmssion of Elect by Others								(878,004)			
5660	Misc Transmission Expenses	2,397	(3,955)						(31,298)	(12,243)	224,184	100,914
5670	Rents											
		21,639	**(36,377)**	**0**	**0**	**0**	**0**	**0**	**(909,302)**	**(50,827)**	**109,027**	**285,350**
	Transmission Maintenance											
5680	Maint Supv & Engineering	312	(430)								(17)	257
5690	Maintenance of Structures	94	(9)								(8)	266
5691	Maintenance of Structures										(43)	984
5692	Maintenance of Structures										(3,451)	(576)
5693	Maintenance of Structures											
5700	Maint of Station Equipment	27,318	(33,461)								(2,363)	(58,621)
5710	Maintenance of Overhead Lines	6,195	(6,105)								(5,134)	19,826
5720	Maint of Underground Lines										(22)	219
5730	Maint of Misc Trnsmssion Plt	1	(2)								(60)	486
	Total	**33,920**	**(40,007)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(11,098)**	**(37,159)**
	Regional Market Expenses - Operations											
5757	SPP Admin-MAM&SC											
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Distribution Expenses - Operations											
5800	Oper Supervision & Engineering	8,650	(17,937)							(7,716)	(20,575)	(40,341)
5810	Load Dispatching											
5820	Station Expenses	1,540	(3,024)								(1,863)	25,941
5830	Overhead Line Expenses	16,879	(59,924)								(102)	1,899
5840	Underground Line Expenses	18,563	(31,644)								(281)	(219)
5850	Street Lighting & Signal Sys E	1,019	(1,811)									
5860	Meter Expenses	34,209	(81,581)								(3,422)	(21,193)
5870	Customer Installations Exp	5,824	(10,090)									
5880	Miscellaneous Distribution Exp	118,491	(238,714)						(124,555)		201,520	76,263
5890	Rents											
	Total	**205,175**	**(444,725)**	**0**	**0**	**0**	**0**	**0**	**(124,555)**	**(7,716)**	**175,277**	**42,350**
	Distribution Expenses - Maintenance											
5900	Maint Supv & Engineering	3,699	(6,828)								(195)	2,415
5910	Maintenance of Structures	44	(100)									
5920	Maint of Station Equipment	3,351	(6,662)								(1,045)	20,050
5930	Maintenance of Overhead Lines	82,418	(262,116)						3,132,290		(629)	10,837
5940	Maint of Underground Lines	7,012	(13,822)									
5950	Maint of Lne Trnf,Rglators&Dvi	578	(2,367)									
5960	Maint of Strt Lghtng & Sgnal S	3,323	(6,711)									
5970	Maintenance of Meters	5,085	(9,115)								(7)	111
5980	Maint of Misc Distribution Plt	2,107	(3,763)									5
	Total	**107,617**	**(311,484)**	**0**	**0**	**0**	**0**	**0**	**3,132,290**	**0**	**(1,876)**	**33,418**
	Cust. Accts . Expense											
9010	Supervision - Customer Accts	6,454	**(11,684)**								(1,575)	20,271

Supporting Schedules:
(a) WP C 2-1 - WP C 2-26

Recap Schedules:
(A) Schedule C-1

Schedule C-2

Southwestern Electric Power Company
Adjustments to Test Year Statement of Utility Operating Income
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing adjustments to the test year statement of utility operating income by account and by adjustment. Do not include adjustments for proposed rate changes on this schedule. Adjustments for proposed rates changes should be shown on Schedule H-1.

		Annualized Payroll	Incentive Compensation	FICA Expense	Credit Line Fees	Rate Case Expense	EE Removal	Fuel and PP Removal	Reg Amort	Aviation	AEPSC Incentives	AEPSC Payroll
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
FERC ACCT.NO.	DESCRIPTION	Adj. No. IS-1	Adj. No. IS-2	Adj. No. IS-3	Adj. No. IS-4	Adj. No. IS-5	Adj. No. IS-6	Adj. No. IS-7	Adj. No. IS-8	Adj. No. IS-9	Adj. No. IS-10	Adj. No. IS-11
9020	Meter Reading Expenses	18,543	**(33,012)**								(1,381)	4,390
9030	Cust Records & Collection Exp	30,657	**(55,122)**								(191,379)	809,878
9040	Uncollectible Accounts											
9050	Misc Customer Accounts Exp										(590)	(40,676)
	Total	**55,654**	**(99,818)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(194,925)**	**793,863**
	Customer Serv. And Informational Expense											
9070	Supervision - Customer Service	14,210	(22,163)				(6,622,074)				(2,760)	(112,335)
9080	Customer Assistance Expenses	30,171	(52,118)				(11,717,220)			(7,411)	(1,470)	(5,765)
9090	Information & Instruct Advrtis											
9100	Misc Cust Svc&Informational Ex										(110)	1,692
9110	Supervision - Sales Expenses											
	Total	**44,381**	**(74,281)**	**0**	**0**	**0**	**(18,339,294)**	**0**	**0**	**(7,411)**	**(4,340)**	**(116,408)**
	Sales Expense											
9120	Demonstrating & Selling Exp										(74)	324
9130	Advertising Exp											
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(74)**	**324**
	Admin. and General Exp. - Operations											
9200	Administrative & Gen Salaries	60,514	4,763,907							(496,882)	(624,644)	(418,835)
9210	Office Supplies and Expenses	129	(327)						(54,121)	(364,293)	(1,872)	(6,145)
9220	Administrative Exp Trnsf - Cr	(13,212)									(9)	0
9230	Outside Services Employed										(22)	176
9240	Property Insurance											
9250	Injuries and Damages	1,806	(2,932)								(2,581)	12,605
9260	Employee Pensions & Benefits										(1,550)	17,823
9270	Franchise Requirements											
9280	Regulatory Commission Exp	6	(14)								(27,062)	229,637
9301	General Advertising Expenses										(554)	6,654
9302	Misc General Expenses	579	(927)		390,220					(9,786)	(4,272)	42,374
9310	Rents											
	Total	**49,822**	**4,759,707**	**0**	**390,220**	**0**	**0**	**0**	**(54,121)**	**(870,961)**	**(662,566)**	**(115,711)**
	Maintenance of General Plant											
9350	Maintenance of General Plant	19,659	(121,841)								(3,121)	29,407
	Total	**19,659**	**(121,841)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(3,121)**	**29,407**
	Total O&M Expense	**1,035,780**	**2,410,850**	**0**	**390,220**	**0**	**(18,339,294)**	**(666,823,931)**	**1,961,130**	**(1,156,583)**	**(620,385)**	**1,469,249**
	Depreciation and Amortization Expense											
4030	Depreciation Expense											
4031	Depr - Asset Retirement Oblig											
4037	Depreciation Expense											
4040	Amortization of Plant											
4073	Regulatory Debits					542,500			(2,256,291)			
4074	Regulatory Credits											
	Total	**0**	**0**	**0**	**0**	**542,500**	**0**	**0**	**(2,256,291)**	**0**	**0**	**0**

Supporting Schedules:
(a) WP C 2-1 - WP C 2-26

Recap Schedules:
(A) Schedule C-1

Southwestern Electric Power Company
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Test Year Ending December 31, 2018
Docket No. 19-008-U

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
FERC ACCT.NO.	DESCRIPTION	Adj. No. IS-1	Adj. No. IS-2	Adj. No. IS-3	Adj. No. IS-4	Adj. No. IS-5	Adj. No. IS-6	Adj. No. IS-7	Adj. No. IS-8	Adj. No. IS-9	Adj. No. IS-10	Adj. No. IS-11
	Taxes Other Than Income Taxes											
4081002	FICA			25,860								
4081003	Federal Unemployment Tax											
408100515	Real Personal Property Taxes											
408100516	Real Personal Property Taxes											
408100517	Real Personal Property Taxes											
408100518	Real Personal Property Taxes											
408100519	Real Personal Property Taxes											
408100615	State Gross Receipts Tax											
408100616	State Gross Receipts Tax											
408100617	State Gross Receipts Tax											
408100618	State Gross Receipts Tax											
4081007	State Unemployment Tax											
408100815	State Franchise Taxes											
408100816	State Franchise Taxes											
408100818	State Franchise Taxes											
408101415	Federal Excise Taxes											
408101416	Federal Excise Taxes											
408101417	Federal Excise Taxes											
408101418	Federal Excise Taxes											
408101716	St Lic-Rgstrtion Tax-Fees											
408101717	St Lic-Rgstrtion Tax-Fees											
408101718	St Lic-Rgstrtion Tax-Fees											
408101815	St Publ Serv Comm Tax-Fees											
408101816	St Publ Serv Comm Tax-Fees											
408101817	St Publ Serv Comm Tax-Fees											
408101818	St Publ Serv Comm Tax-Fees											
408101900	State Sales and Use Taxes											
408101914	State Sales and Use Taxes											
408101915	State Sales and Use Taxes											
408101916	State Sales and Use Taxes											
408101917	State Sales and Use Taxes											
408101918	State Sales and Use Taxes											
408102216	Municipal License Fees											
408102217	Municipal License Fees											
408102218	Municipal License Fees											
408102316	Local Privilege-Franchise Tax											
408102317	Local Privilege-Franchise Tax											
408102318	Local Privilege-Franchise Tax											
408102716	Misc State and Local Taxes											
408102915	Real-Pers Prop Tax-Cap Leases											
408102916	Real-Pers Prop Tax-Cap Leases											
408102917	Real-Pers Prop Tax-Cap Leases											
408102918	Real-Pers Prop Tax-Cap Leases											
4081033	Fringe Benefit Loading - FICA											
4081034	Fringe Benefit Loading - FUT											
4081035	Fringe Benefit Loading - SUT											
	Total	**0**	**0**	**25,860**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Supporting Schedules:
(a) WP C 2-1 - WP C 2-26

Recap Schedules:
(A) Schedule C-1

Southwestern Electric Power Company
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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
FERC ACCT.NO.	DESCRIPTION	Adj. No. IS-1	Adj. No. IS-2	Adj. No. IS-3	Adj. No. IS-4	Adj. No. IS-5	Adj. No. IS-6	Adj. No. IS-7	Adj. No. IS-8	Adj. No. IS-9	Adj. No. IS-10	Adj. No. IS-11
	Other Provisions											
4111	Accretion expense											
4118	Gain Disposition of Allowances											
		0	0	0	0	0	0	0	0	0	0	0
	TOTAL EXPENSES	1,035,780	2,410,850	25,860	390,220	542,500	(18,339,294)	(666,823,931)	(295,161)	(1,156,583)	(620,385)	1,469,249
	OPERATING INCOME BEFORE	(1,035,780)	(2,410,850)	(25,860)	(390,220)	(542,500)	18,339,294	666,823,931	(114,093)	1,156,583	620,385	(1,469,249)
	Income Taxes											
4091	FIT -current											
4091002	SIT - current											
4092	Income Tax, Oth Inc & Ded											
	Current	0	0	0	0	0	0	0	0	0	0	0
4101	Prov Def Inc Tax, Util Oper In											
4102	Prov Def I/T Oth Inc & Ded											
	Provision for Deferred	0	0	0	0	0	0	0	0	0	0	0
4111	Prov Def I/T-Cr Util Oper Inc											
4112	Prv Def I/T-Cr Oth I&D											
4114	ITC Adj, Utility Operations											
	Writeback of Deferred	0	0	0	0	0	0	0	0	0	0	0
	Total Income Tax expense	0	0	0	0	0	0	0	0	0	0	0
	Rounding											
	UTILITY OPERATING INCOME	(1,035,780)	(2,410,850)	(25,860)	(390,220)	(542,500)	18,339,294	666,823,931	(114,093)	1,156,583	620,385	(1,469,249)

Supporting Schedules:
(a) WP C 2-1 - WP C 2-26

Recap Schedules:
(A) Schedule C-1

Schedule C-2

Southwestern Electric Power Company
Adjustments to Test Year Statement of U
Test Year Ending December 31, 2018
Docket No. 19-008-U

(1) FERC ACCT.NO.	(2) DESCRIPTION	AEPSC LTIP (14) Adj. No. IS-12	Bad Debt (15) Adj. No. IS-13	Annualize Depr (16) Adj. No. IS-14	Turk Depreciation Exp Removal (17) Adj. No. IS-14-1	SPP Expenses (18) Adj. No. IS-15	Econ Development (19) Adj. No. IS-16	Property Tax (20) Adj. No. IS-17	Revenue Adj (21) Adj. No. IS-18	Expense Removal (22) Adj. No. IS-19
FERC	**FERC Title Account**									
4400	**Residential Sales**									
4400001	Residential Sales-W/Space Htg								(66,956,833)	
4400002	Residential Sales-W/O Space Ht									
4400005	Residential Fuel Rev								(198,322,908)	
4400006	Residential O/U Fuel Rev									
	4400 Total	**0**	**0**	**0**		**0**	**0**	**0**	**(265,279,741)**	**0**
4420	**Commercial & Industrial Sales**									
4420001	Commercial Sales								100,033,124	
4420002	Industrial Sales (Excl Mines)								(118,249,670)	
4420006	Sales to Pub Auth - Schools									
4420007	Sales to Pub Auth - Ex Schools									
4420013	Commercial Fuel Rev								(185,377,647)	
4420014	Commercial O/U Fuel Rev									
4420016	Industrial Fuel Rev								(161,486,634)	
4420017	Industrial O/U Fuel Rev									
	4420 Total	**0**	**0**	**0**		**0**	**0**	**0**	**(365,080,827)**	**0**
4440	**Public Street/Highway Lighting**									
4440000	Public Street/Highway Lighting								(30,602,550)	
4440002	Public St & Hwy Light Fuel Rev								(2,477,350)	
4440003	Pb St & Hwy Light O/U Fuel Rev									
	4440 Total	**0**	**0**	**0**		**0**	**0**	**0**	**(33,079,900)**	**0**
4470	**Sales for Resale**									
4470001	Sales for Resale - Assoc Cos									
4470002	Sales for Resale - NonAssoc								482,231	
4470006	Sales for Resale-Bookout Sales									
4470010	Sales for Resale-Bookout Purch									
4470027	Whsal/Muni/Pb Ath Fuel Rev								(139,554,638)	
4470028	Sale/Resale - NA - Fuel Rev									
4470032	Capacity Revenue - Affiliated									
4470033	Whsal/Muni/Pub Auth Base Rev									
4470035	Sls for Rsl - Fuel Rev - Assoc									
4470036	Sales for Resale- Fuel - ERCOT									
4470074	Sale for Resale-Aff-Trnf Price									
4470081	Financial Spark Gas - Realized									
4470082	Financial Electric Realized									
4470131	Non-Trading Bookout Purch-OSS									
4470136	SPP Rev Neutrality Ded-Sales									
4470150	Transm. Rev.-Dedic. Whlsl/Muni									
4470175	OSS Sharing Reclass - Retail									
4470176	OSS Sharing Reclass-Reduction									
4470219	Merchant Fuel Revenue									
4470223	Merchant Sales Margin									
4470320	SPP Net Regulation OSS									
4470321	SPP Net Spinning Reserve OSS									
4470324	SPP Net Supp Reserve OSS									
4470326	SPP Net Marginal Losses OSS									
4470328	SPP Net Make Whole Payment OS									
4470332	SPP Congestion Costs OSS									

Supporting Schedules:
(a) WP C 2-1 - WP C 2-26

Recap Schedules:
(A) Schedule C-1

Southwestern Electric Power Company
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Test Year Ending December 31, 2018
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(1) FERC ACCT.NO.	(2) DESCRIPTION	AEPSC LTIP (14) Adj. No. IS-12	Bad Debt (15) Adj. No. IS-13	Annualize Depr (16) Adj. No. IS-14	Turk Depreciation Exp Removal (17) Adj. No. IS-14-1	SPP Expenses (18) Adj. No. IS-15	Econ Development (19) Adj. No. IS-16	Property Tax (20) Adj. No. IS-17	Revenue Adj (21) Adj. No. IS-18	Expense Removal (22) Adj. No. IS-19
	4470 Total	**0**	**0**	**0**		**0**	**0**	**0**	**(139,072,407)**	**0**
4491	**Provision for Rate Refunds**									
4491002	Prov Rate Refund-Nonaffiliated								63,427,415	
4491003	Prov Rate Refund - Retail									
4491004	Prov Rate Refund - Affiliated									
4491018	Prov Rate Refund - Tax Reform									
4491019	Prov Rate Refund-Exces Protect									
	4491 Total	**0**	**0**	**0**		**0**	**0**	**0**	**63,427,415**	**0**
4500	**Forfeited Discounts**									
4500000	Forfeited Discounts									
	4500 Total	**0**	**0**	**0**		**0**	**0**	**0**	**0**	**0**
4510	**Misc Service Revenues**									
4510001	Misc Service Rev - Nonaffil									
	4510 Total	**0**	**0**	**0**		**0**	**0**	**0**	**0**	**0**
4540	**Rent From Electric Property**									
4540001	Rent From Elect Property - Af								(6,897)	
4540002	Rent From Elect Property-NAC									
4540004	Rent From Elect Prop-ABD-Nonaf									
4540005	Rent from Elec Prop-Pole Attch									
	4540 Total	**0**	**0**	**0**		**0**	**0**	**0**	**(6,897)**	**0**
4560	**Other Electric Revenues**									
4560010	Oth Elect Rev - Royalties									
4560012	Oth Elect Rev - Nonaffiliated									
4560013	Oth Elect Rev-Trans-Nonaffil								8,662,712	
4560015	Other Electric Revenues - ABD									
4560025	Plant Operations O/H Revenues									
4560041	Miscellaneous Revenue-NonAffil									
4560043	Oth Elec Rv-Trn-Aff-Trnf Price									
4560102	Oth Elect Rev-Trans-ERCOT area									
	4560 Total	**0**	**0**	**0**		**0**	**0**	**0**	**8,662,712**	**0**
4561	**Other Electric Revenues**									
4561008	SPP Non-Affil. Base Fundng Rev									
4561009	SPP Affil. Base Funding Cost									
4561010	SPP Affl. Base Funding Rev									
4561011	SPP Pt to Pt Trans Serv Rev									
4561012	SPP Direct Assignment									
4561013	SPP Affiliated NITS Revenue									
4561014	SPP Ancillary Services									
4561015	SPP Ancillary Schedule 1									
4561016	SPP Affiliated Trans NITS Cost									
4561017	Oth Elect Revenues - Ancillary									
4561019	Oth Elec Rev Trans Non Aff									
4561020	Oth Elec Rev-Trans-Aff-SPP									
4561021	SPP NITS									
4561038	SPP Pt to Pt Trans Affil Cost									
4561039	SPP Pt to Pt Trans Affil Rev									
4561040	Affil. SPPAncillary Sch.1 Cost									
4561041	Affil. SPPAncillary Sch. 1 Rev									

Southwestern Electric Power Company
Adjustments to Test Year Statement of U
Test Year Ending December 31, 2018
Docket No. 19-008-U

		AEPSC LTIP	Bad Debt	Annualize Depr	Turk Depreciation Exp Removal	SPP Expenses	Econ Development	Property Tax	Revenue Adj	Expense Removal
(1)	(2)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)
FERC ACCT.NO.	DESCRIPTION	Adj. No. IS-12	Adj. No. IS-13	Adj. No. IS-14	Adj. No. IS-14-1	Adj. No. IS-15	Adj. No. IS-16	Adj. No. IS-17	Adj. No. IS-18	Adj. No. IS-19
4561042	SPP Base Funding Contra									
4561065	Provision RTO Rev-NonAff									
	4561 Total	**0**	**0**	**0**		**0**	**0**	**0**	**0**	**0**
	TOTAL REVENUES	**0**	**0**	**0**		**0**	**0**	**0**	**(730,429,645)**	**0**
	Production Operations									
5000	Oper Supervision & Engineering	(80,386)								(584)
5010	Fuel	(3,502)								
5020	Steam Expenses	1,329								
5050	Electric Expenses	81								
5060	Misc Steam Power Expenses	91,366								(521)
5070	Rents									
5080	Operations - Supplies and Expense									
5090	Allowance Consumption SO2									
	Total	**8,888**	**0**	**0**		**0**	**0**	**0**	**0**	**(1,105)**
	Production Maintenance									
5100	Maint Supv & Engineering	(19,386)								
5110	Maintenance of Structures	6,082								
5120	Maintenance of Boiler Plant	(18,761)								
5130	Maintenance of Electric Plant	3,235								
5140	Maintenance of Misc Steam Plt	1,395								(159)
	Total	**(27,435)**	**0**	**0**		**0**	**0**	**0**	**0**	**(159)**
	Other Power Generation Opera									
5470	Fuel									
5460 & 54	Generation Expenses									
	Total	**0**	**0**	**0**		**0**	**0**	**0**	**0**	**0**
	Other Power Generation Maint									
5530	Maintenance of Generating Plt	52								
5540	Maint of Misc Oth Pwr Gneratn									
	Total	**52**	**0**	**0**		**0**	**0**	**0**	**0**	**0**
	Other Power Supply Expenses									
5550	Purchased Power									
5560	Sys Control & Load Dispatching	(7,993)								
5570	Other Expenses	(12,629)								
	Total	**(20,622)**	**0**	**0**		**0**	**0**	**0**	**0**	**0**
	Transmission Operations									
5600	Oper Supervision & Engineering	11,594								(329)
5611	Load Dispatching	(1)								
5612	Load Dispatching	(3,470)								
5613	Load Dispatching									
5614	Load Dispatching									
5615	Load Dispatching	(424)								
5616	Load Dispatching	1								
5618	Load Dispatching									
5620	Station Expenses	18								
5630	Overhead Line Expenses	135								(36)

Supporting Schedules:
(a) WP C 2-1 - WP C 2-26

Recap Schedules:
(A) Schedule C-1

Southwestern Electric Power Company
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		AEPSC LTIP	Bad Debt	Annualize Depr	Turk Depreciation Exp Removal	SPP Expenses	Econ Development	Property Tax	Revenue Adj	Expense Removal
(1)	(2)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)
FERC ACCT.NO.	DESCRIPTION	Adj. No. IS-12	Adj. No. IS-13	Adj. No. IS-14	Adj. No. IS-14-1	Adj. No. IS-15	Adj. No. IS-16	Adj. No. IS-17	Adj. No. IS-18	Adj. No. IS-19
5640	Underground Line Expenses									
5650	Trnsmssion of Elect by Others					10,130,133				
5660	Misc Transmission Expenses	51,460								(24)
5670	Rents									
		59,313	**0**	**0**		**10,130,133**	**0**	**0**	**0**	**(389)**
	Transmission Maintenance									
5680	Maint Supv & Engineering	8								
5690	Maintenance of Structures	4								
5691	Maintenance of Structures	25								
5692	Maintenance of Structures	(122)								
5693	Maintenance of Structures									
5700	Maint of Station Equipment	(1,477)								(58)
5710	Maintenance of Overhead Lines	916								
5720	Maint of Underground Lines	5								
5730	Maint of Misc Trnsmssion Plt	14								
	Total	**(627)**	**0**	**0**		**0**	**0**	**0**	**0**	**(58)**
	Regional Market Expenses - O									
5757	SPP Admin-MAM&SC									
	Total	**0**	**0**	**0**		**0**	**0**	**0**	**0**	**0**
	Distribution Expenses - Opera									
5800	Oper Supervision & Engineering	7,127								(19)
5810	Load Dispatching									
5820	Station Expenses	653								
5830	Overhead Line Expenses	83								
5840	Underground Line Expenses	75								
5850	Street Lighting & Signal Sys E									
5860	Meter Expenses	905								(706)
5870	Customer Installations Exp									
5880	Miscellaneous Distribution Exp	53,541								(648)
5890	Rents									
	Total	**62,384**	**0**	**0**		**0**	**0**	**0**	**0**	**(1,373)**
	Distribution Expenses - Mainte									
5900	Maint Supv & Engineering	50								
5910	Maintenance of Structures									
5920	Maint of Station Equipment	463								
5930	Maintenance of Overhead Lines	193								(514)
5940	Maint of Underground Lines									
5950	Maint of Lne Trnf,Rglators&Dvi									
5960	Maint of Strt Lghtng & Sgnal S									
5970	Maintenance of Meters	3								
5980	Maint of Misc Distribution Plt	0								
	Total	**709**	**0**	**0**		**0**	**0**	**0**	**0**	**(514)**
	Cust. Accts . Expense									
9010	Supervision - Customer Accts	418								(579)

Supporting Schedules:
(a) WP C 2-1 - WP C 2-26

Recap Schedules:
(A) Schedule C-1

Southwestern Electric Power Company
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(1) FERC ACCT.NO.	(2) DESCRIPTION	AEPSC LTIP (14) Adj. No. IS-12	Bad Debt (15) Adj. No. IS-13	Annualize Depr (16) Adj. No. IS-14	Turk Depreciation Exp Removal (17) Adj. No. IS-14-1	SPP Expenses (18) Adj. No. IS-15	Econ Development (19) Adj. No. IS-16	Property Tax (20) Adj. No. IS-17	Revenue Adj (21) Adj. No. IS-18	Expense Removal (22) Adj. No. IS-19
9020	Meter Reading Expenses	408								(308)
9030	Cust Records & Collection Exp	45,382								(343)
9040	Uncollectible Accounts		3,133,882							
9050	Misc Customer Accounts Exp	165								
	Total	**46,373**	**3,133,882**	**0**		**0**	**0**	**0**	**0**	**(1,230)**
	Customer Serv. And Informatic									
9070	Supervision - Customer Service	741								(7,873)
9080	Customer Assistance Expenses	402					300,000			
9090	Information & Instruct Advrtis									
9100	Misc Cust Svc&Informational Ex	41								
9110	Supervision - Sales Expenses									
	Total	**1,184**	**0**	**0**		**0**	**300,000**	**0**	**0**	**(7,873)**
	Sales Expense									
9120	Demonstrating & Selling Exp	(108)								(55)
9130	Advertising Exp									
	Total	**(108)**	**0**	**0**		**0**	**0**	**0**	**0**	**(55)**
	Admin. and General Exp. - Ope									
9200	Administrative & Gen Salaries	(1,368,160)								
9210	Office Supplies and Expenses	(182)								(19,674)
9220	Administrative Exp Trnsf - Cr	0								
9230	Outside Services Employed	4								(9)
9240	Property Insurance									
9250	Injuries and Damages	527								
9260	Employee Pensions & Benefits	1,160								
9270	Franchise Requirements									
9280	Regulatory Commission Exp	19,542								
9301	General Advertising Expenses	146								(129)
9302	Misc General Expenses	1,976								(22,962)
9310	Rents									
	Total	**(1,344,987)**	**0**	**0**		**0**	**0**	**0**	**0**	**(42,774)**
	Maintenance of General Plant									
9350	Maintenance of General Plant	783								(605)
	Total	**783**	**0**	**0**		**0**	**0**	**0**	**0**	**(605)**
	Total O&M Expense	**(1,214,093)**	**3,133,882**	**0**		**10,130,133**	**300,000**	**0**	**0**	**(56,135)**
	Depreciation and Amortization									
4030	Depreciation Expense			29,388,064	(34,642,317)					
4031	Depr - Asset Retirement Oblig									
4037	Depreciation Expense									
4040	Amortization of Plant									
4073	Regulatory Debits									
4074	Regulatory Credits									
	Total	**0**	**0**	**29,388,064**	**(34,642,317)**	**0**	**0**	**0**	**0**	**0**

Supporting Schedules:
(a) WP C 2-1 - WP C 2-26

Recap Schedules:
(A) Schedule C-1

Southwestern Electric Power Company
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(1) FERC ACCT.NO.	(2) DESCRIPTION	AEPSC LTIP (14) Adj. No. IS-12	Bad Debt (15) Adj. No. IS-13	Annualize Depr (16) Adj. No. IS-14	Turk Depreciation Exp Removal (17) Adj. No. IS-14-1	SPP Expenses (18) Adj. No. IS-15	Econ Development (19) Adj. No. IS-16	Property Tax (20) Adj. No. IS-17	Revenue Adj (21) Adj. No. IS-18	Expense Removal (22) Adj. No. IS-19
	Taxes Other Than Income Taxe									
4081002	FICA									
4081003	Federal Unemployment Tax									
408100515	Real Personal Property Taxes									
408100516	Real Personal Property Taxes									
408100517	Real Personal Property Taxes							911,696		
408100518	Real Personal Property Taxes							(64,201,415)		
408100519	Real Personal Property Taxes							62,177,492		
408100615	State Gross Receipts Tax									
408100616	State Gross Receipts Tax									
408100617	State Gross Receipts Tax							(2)		
408100618	State Gross Receipts Tax							(104)		
4081007	State Unemployment Tax									
408100815	State Franchise Taxes									
408100816	State Franchise Taxes									
408100818	State Franchise Taxes									
408101415	Federal Excise Taxes									
408101416	Federal Excise Taxes									
408101417	Federal Excise Taxes									
408101418	Federal Excise Taxes									
408101716	St Lic-Rgstrtion Tax-Fees									
408101717	St Lic-Rgstrtion Tax-Fees									
408101718	St Lic-Rgstrtion Tax-Fees									
408101815	St Publ Serv Comm Tax-Fees									
408101816	St Publ Serv Comm Tax-Fees									
408101817	St Publ Serv Comm Tax-Fees									
408101818	St Publ Serv Comm Tax-Fees									
408101900	State Sales and Use Taxes							311,500		
408101914	State Sales and Use Taxes									
408101915	State Sales and Use Taxes									
408101916	State Sales and Use Taxes							(185,277)		
408101917	State Sales and Use Taxes							(246)		
408101918	State Sales and Use Taxes							(4,876)		
408102216	Municipal License Fees									
408102217	Municipal License Fees									
408102218	Municipal License Fees									
408102316	Local Privilege-Franchise Tax									
408102317	Local Privilege-Franchise Tax									
408102318	Local Privilege-Franchise Tax									
408102716	Misc State and Local Taxes									
408102915	Real-Pers Prop Tax-Cap Leases									
408102916	Real-Pers Prop Tax-Cap Leases									
408102917	Real-Pers Prop Tax-Cap Leases							(9,469)		
408102918	Real-Pers Prop Tax-Cap Leases									
4081033	Fringe Benefit Loading - FICA									
4081034	Fringe Benefit Loading - FUT									
4081035	Fringe Benefit Loading - SUT									
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**(1,000,701)**	**0**	**0**

Supporting Schedules:
(a) WP C 2-1 - WP C 2-26

Recap Schedules:
(A) Schedule C-1

Southwestern Electric Power Company
Adjustments to Test Year Statement of U
Test Year Ending December 31, 2018
Docket No. 19-008-U

(1) FERC ACCT.NO.	(2) DESCRIPTION	AEPSC LTIP (14) Adj. No. IS-12	Bad Debt (15) Adj. No. IS-13	Annualize Depr (16) Adj. No. IS-14	Turk Depreciation Exp Removal (17) Adj. No. IS-14-1	SPP Expenses (18) Adj. No. IS-15	Econ Development (19) Adj. No. IS-16	Property Tax (20) Adj. No. IS-17	Revenue Adj (21) Adj. No. IS-18	Expense Removal (22) Adj. No. IS-19
	Other Provisions									
4111	Accretion expense									
4118	Gain Disposition of Allowances									
		0	0	0	0	0	0	0	0	0
	TOTAL EXPENSES	(1,214,093)	3,133,882	29,388,064	(34,642,317)	10,130,133	300,000	(1,000,701)	0	(56,135)
	OPERATING INCOME BEFORE	1,214,093	(3,133,882)	(29,388,064)	34,642,317	(10,130,133)	(300,000)	1,000,701	(730,429,645)	56,135
	Income Taxes									
4091	FIT -current									
4091002	SIT - current									
4092	Income Tax, Oth Inc & Ded									
	Current	0	0	0		0	0	0	0	0
4101	Prov Def Inc Tax, Util Oper In									
4102	Prov Def I/T Oth Inc & Ded									
	Provision for Deferred	0	0	0		0	0	0	0	0
4111	Prov Def I/T-Cr Util Oper Inc									
4112	Prv Def I/T-Cr Oth I&D									
4114	ITC Adj, Utility Operations									
	Writeback of Deferred	0	0	0		0	0	0	0	0
	Total Income Tax expense	0	0	0		0	0	0	0	0
	Rounding									
	UTILITY OPERATING INCOME	1,214,093	(3,133,882)	(29,388,064)	34,642,317	(10,130,133)	(300,000)	1,000,701	(730,429,645)	56,135

Schedule C-2

Southwestern Electric Power Company
Adjustments to Test Year Statement of U
Test Year Ending December 31, 2018
Docket No. 19-008-U

(1) FERC ACCT.NO.	(2) DESCRIPTION	LA Deferred Fuel (23) Adj. No. IS-20	Turk Expense Removal (24) Adj. No. IS-21	Grid Assurance (25) Adj. No. IS-22	EEI (26) Adj. No. IS-23	Advertising (27) Adj. No. IS-24	Customer Account Processing Expense (28) Adj. No. IS-25	Income Tax (29) Adj. No. IS-26	(30) TOTAL ADJUSTMENTS (a) (A)	Test Year End 12/31/18	Pro forma Year
FERC	**FERC Title** **Account**										
4400	**Residential Sales**										
4400001	Residential Sales-W/Space Htg								(66,956,833)	111,073,810.76	44,116,977.76
4400002	Residential Sales-W/O Space Ht								0	358,844,977.42	358,844,977.42
4400005	Residential Fuel Rev								(198,322,908)	196,922,958.23	(1,399,949.77)
4400006	Residential O/U Fuel Rev								0	1,399,949.76	1,399,949.76
	4400 Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(265,279,741)**	**668,241,696.17**	**402,961,955.17**
4420	**Commercial & Industrial Sales**										
4420001	Commercial Sales								100,033,124	294,667,899.87	394,701,023.87
4420002	Industrial Sales (Excl Mines)								(118,249,670)	165,419,443.55	47,169,773.55
4420006	Sales to Pub Auth - Schools								0	7,157,947.20	7,157,947.20
4420007	Sales to Pub Auth - Ex Schools								0	53,810,707.36	53,810,707.36
4420013	Commercial Fuel Rev								(185,377,647)	183,995,343.11	(1,382,303.89)
4420014	Commercial O/U Fuel Rev								0	1,382,303.47	1,382,303.47
4420016	Industrial Fuel Rev								(161,486,634)	159,926,572.10	(1,560,061.90)
4420017	Industrial O/U Fuel Rev								0	1,560,061.41	1,560,061.41
	4420 Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(365,080,827)**	**867,920,278.07**	**502,839,451.07**
4440	**Public Street/Highway Lighting**										
4440000	Public Street/Highway Lighting								(30,602,550)	6,280,140.73	(24,322,409.27)
4440002	Public St & Hwy Light Fuel Rev								(2,477,350)	2,461,819.28	(15,530.72)
4440003	Pb St & Hwy Light O/U Fuel Rev								0	15,530.46	15,530.46
	4440 Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(33,079,900)**	**8,757,490.47**	**(24,322,409.53)**
4470	**Sales for Resale**										
4470001	Sales for Resale - Assoc Cos								0	(87,843.72)	(87,843.72)
4470002	Sales for Resale - NonAssoc								482,231	3,484,802.06	3,967,033.06
4470006	Sales for Resale-Bookout Sales								0	1,078,635.08	1,078,635.08
4470010	Sales for Resale-Bookout Purch								0	(820,665.33)	(820,665.33)
4470027	Whsal/Muni/Pb Ath Fuel Rev								(139,554,638)	77,110,895.65	(62,443,742.35)
4470028	Sale/Resale - NA - Fuel Rev								0	41,919,784.35	41,919,784.35
4470032	Capacity Revenue - Affiliated								0	0.00	0.00
4470033	Whsal/Muni/Pub Auth Base Rev								0	80,072,511.61	80,072,511.61
4470035	Sls for Rsl - Fuel Rev - Assoc								0	0.00	0.00
4470036	Sales for Resale- Fuel - ERCOT								0	202,184.14	202,184.14
4470074	Sale for Resale-Aff-Trnf Price								0	0.00	0.00
4470081	Financial Spark Gas - Realized								0	0.00	0.00
4470082	Financial Electric Realized								0	0.00	0.00
4470131	Non-Trading Bookout Purch-OSS								0	1,942.66	1,942.66
4470136	SPP Rev Neutrality Ded-Sales								0	220,208.35	220,208.35
4470150	Transm. Rev.-Dedic. Whlsl/Muni								0	3,981,781.30	3,981,781.30
4470175	OSS Sharing Reclass - Retail								0	9,329,841.83	9,329,841.83
4470176	OSS Sharing Reclass-Reduction								0	(9,329,841.83)	(9,329,841.83)
4470219	Merchant Fuel Revenue								0	5,899,836.67	5,899,836.67
4470223	Merchant Sales Margin								0	3,717,573.19	3,717,573.19
4470320	SPP Net Regulation OSS								0	994,732.76	994,732.76
4470321	SPP Net Spinning Reserve OSS								0	2,288,909.14	2,288,909.14
4470324	SPP Net Supp Reserve OSS								0	27,385.98	27,385.98
4470326	SPP Net Marginal Losses OSS								0	827,822.25	827,822.25
4470328	SPP Net Make Whole Payment OS								0	11,467.62	11,467.62
4470332	SPP Congestion Costs OSS								0	2,676,966.68	2,676,966.68

Supporting Schedules:
(a) WP C 2-1 - WP C 2-26

Recap Schedules:
(A) Schedule C-1

Schedule C-2

Southwestern Electric Power Company
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(1) FERC ACCT.NO.	(2) DESCRIPTION	(23) LA Deferred Fuel Adj. No. IS-20	(24) Turk Expense Removal Adj. No. IS-21	(25) Grid Assurance Adj. No. IS-22	(26) EEI Adj. No. IS-23	(27) Advertising Adj. No. IS-24	(28) Customer Account Processing Expense Adj. No. IS-25	(29) Income Tax Adj. No. IS-26	(30) TOTAL ADJUSTMENTS (a) (A)	Test Year End 12/31/18	Pro forma Year
	4470 Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(139,072,407)**	**223,608,930.44**	**84,536,523.44**
4491	**Provision for Rate Refunds**										
4491002	Prov Rate Refund-Nonaffiliated								63,427,415	(15,831,332.22)	47,596,082.78
4491003	Prov Rate Refund - Retail								0	(0.11)	(0.11)
4491004	Prov Rate Refund - Affiliated								0	0.00	0.00
4491018	Prov Rate Refund - Tax Reform								0	(31,852,371.05)	(31,852,371.05)
4491019	Prov Rate Refund-Exces Protect								0	(15,743,711.92)	(15,743,711.92)
	4491 Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**63,427,415**	**(63,427,415.30)**	**(0.30)**
4500	**Forfeited Discounts**										
4500000	Forfeited Discounts								0	5,032,195.20	5,032,195.20
	4500 Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**5,032,195.20**	**5,032,195.20**
4510	**Misc Service Revenues**										
4510001	Misc Service Rev - Nonaffil								0	2,250,904.47	2,250,904.47
	4510 Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**2,250,904.47**	**2,250,904.47**
4540	**Rent From Electric Property**										
4540001	Rent From Elect Property - Af								(6,897)	1,628,124.58	1,621,227.58
4540002	Rent From Elect Property-NAC								0	3,095,165.23	3,095,165.23
4540004	Rent From Elect Prop-ABD-Nonaf								0	22,552.43	22,552.43
4540005	Rent from Elec Prop-Pole Attch								0	4,823,031.36	4,823,031.36
	4540 Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(6,897)**	**9,568,873.60**	**9,561,976.60**
4560	**Other Electric Revenues**										
4560010	Oth Elect Rev - Royalties								0	488,963.45	488,963.45
4560012	Oth Elect Rev - Nonaffiliated								0	1,853,527.39	1,853,527.39
4560013	Oth Elect Rev-Trans-Nonaffil								8,662,712	466,408.88	9,129,120.88
4560015	Other Electric Revenues - ABD								0	780,171.01	780,171.01
4560025	Plant Operations O/H Revenues								0	3,207,125.38	3,207,125.38
4560041	Miscellaneous Revenue-NonAffil								(409,254)	0.00	(409,254.00)
4560043	Oth Elec Rv-Trn-Aff-Trnf Price								0	0.00	0.00
4560102	Oth Elect Rev-Trans-ERCOT area								0	0.00	0.00
	4560 Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**8,253,458**	**6,796,196.11**	**15,049,654.11**
4561	**Other Electric Revenues**										
4561008	SPP Non-Affil. Base Fundng Rev								0	44,598,465.38	44,598,465.38
4561009	SPP Affil. Base Funding Cost								0	(22,334,934.90)	(22,334,934.90)
4561010	SPP Affl. Base Funding Rev								0	29,101,095.03	29,101,095.03
4561011	SPP Pt to Pt Trans Serv Rev								0	8,940,750.65	8,940,750.65
4561012	SPP Direct Assignment								0	1,246,072.47	1,246,072.47
4561013	SPP Affiliated NITS Revenue								0	80,599,372.16	80,599,372.16
4561014	SPP Ancillary Services								0	298,591.01	298,591.01
4561015	SPP Ancillary Schedule 1								0	1,262,246.07	1,262,246.07
4561016	SPP Affiliated Trans NITS Cost								0	(64,489,076.35)	(64,489,076.35)
4561017	Oth Elect Revenues - Ancillary								0	350,490.00	350,490.00
4561019	Oth Elec Rev Trans Non Aff								0	0.00	0.00
4561020	Oth Elec Rev-Trans-Aff-SPP								0	0.00	0.00
4561021	SPP NITS								0	25,480,554.57	25,480,554.57
4561038	SPP Pt to Pt Trans Affil Cost								0	0.00	0.00
4561039	SPP Pt to Pt Trans Affil Rev								0	0.00	0.00
4561040	Affil. SPPAncillary Sch.1 Cost								0	(1,766,633.88)	(1,766,633.88)
4561041	Affil. SPPAncillary Sch. 1 Rev								0	1,903,763.03	1,903,763.03

Supporting Schedules:
(a) WP C 2-1 - WP C 2-26

Recap Schedules:
(A) Schedule C-1

Southwestern Electric Power Company
Adjustments to Test Year Statement of U
Test Year Ending December 31, 2018
Docket No. 19-008-U

		LA Deferred Fuel	Turk Expense Removal	Grid Assurance	EEI	Advertising	Customer Account Processing Expense	Income Tax			
(1) FERC ACCT.NO.	(2) DESCRIPTION	(23) Adj. No. IS-20	(24) Adj. No. IS-21	(25) Adj. No. IS-22	(26) Adj. No. IS-23	(27) Adj. No. IS-24	(28) Adj. No. IS-25	(29) Adj. No. IS-26	(30) TOTAL ADJUSTMENTS (a) (A)	Test Year End 12/31/18	Pro forma Year
4561042	SPP Base Funding Contra								0	409,255.00	409,255.00
4561065	Provision RTO Rev-NonAff								0	(3,144,980.00)	(3,144,980.00)
	4561 Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**102,455,030.24**	**102,455,030.24**
	TOTAL REVENUES	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(730,838,899)**	**1,831,204,179.47**	**1,100,365,280.47**
	Production Operations										
5000	Oper Supervision & Engineering		(793,268)						(1,333,468)	19,393,202.68	18,059,734.68
5010	Fuel								(472,602,630)	491,991,246.40	19,388,616.40
5020	Steam Expenses								(4,205,078)	19,791,904.41	15,586,826.41
5050	Electric Expenses		(2,489,268)						(2,607,307)	8,701,391.89	6,094,084.89
5060	Misc Steam Power Expenses		(976,525)						(657,320)	21,398,629.14	20,741,309.14
5070	Rents								0	1,869.14	1,869.14
5080	Operations - Supplies and Expense								0	0.00	0.00
5090	Allowance Consumption SO2								(29,861)	287,122.37	257,261.37
	Total	**0**	**(4,259,061)**	**0**	**0**	**0**	**0**	**0**	**(481,435,664)**	**561,565,366.03**	**80,129,702.03**
	Production Maintenance										
5100	Maint Supv & Engineering		(785,860)						(821,612)	6,094,752.50	5,273,140.50
5110	Maintenance of Structures		(1,435,609)						(1,256,302)	4,093,958.07	2,837,656.07
5120	Maintenance of Boiler Plant		(6,898,165)						(7,436,484)	53,210,987.50	45,774,503.50
5130	Maintenance of Electric Plant		(802,413)						(709,769)	6,289,299.44	5,579,530.44
5140	Maintenance of Misc Steam Plt		(891,020)						(873,005)	4,979,078.77	4,106,073.77
	Total	**0**	**(10,813,067)**	**0**	**0**	**0**	**0**	**0**	**(11,097,172)**	**74,668,076.28**	**63,570,904.28**
	Other Power Generation Opera										
5470	Fuel								(19,001,320)	19,001,319.95	(0.05)
5460 & 54	Generation Expenses								(4,083)	639,751.33	635,668.33
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(19,005,403)**	**19,641,071.28**	**635,668.28**
	Other Power Generation Maint										
5530	Maintenance of Generating Plt								516	633,389.83	633,905.83
5540	Maint of Misc Oth Pwr Gneratn								0	16,954.22	16,954.22
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**516**	**650,344.05**	**650,860.05**
	Other Power Supply Expenses										
5550	Purchased Power								(171,126,607)	180,176,089.52	9,049,482.52
5560	Sys Control & Load Dispatching								100,498	1,821,858.96	1,922,356.96
5570	Other Expenses	(4,038,022)	15,264						(3,893,501)	7,587,325.76	3,693,824.76
	Total	**(4,038,022)**	**15,264**	**0**	**0**	**0**	**0**	**0**	**(174,919,610)**	**189,585,274.24**	**14,665,664.24**
	Transmission Operations										
5600	Oper Supervision & Engineering								204,652	7,240,688.44	7,445,340.44
5611	Load Dispatching								(5,419)	121.31	(5,297.69)
5612	Load Dispatching								(154,361)	1,179,512.80	1,025,151.80
5613	Load Dispatching								0	1,056.96	1,056.96
5614	Load Dispatching								0	11,693,539.72	11,693,539.72
5615	Load Dispatching								(20,775)	190,390.47	169,615.47
5616	Load Dispatching								7	94.33	101.33
5618	Load Dispatching								0	1,482,600.89	1,482,600.89
5620	Station Expenses								(2,037)	540,343.99	538,306.99
5630	Overhead Line Expenses								2,936	421,894.87	424,830.87

Supporting Schedules:
(a) WP C 2-1 - WP C 2-26

Recap Schedules:
(A) Schedule C-1

Southwestern Electric Power Company
Adjustments to Test Year Statement of U
Test Year Ending December 31, 2018
Docket No. 19-008-U

(1) FERC ACCT.NO.	(2) DESCRIPTION	LA Deferred Fuel (23) Adj. No. IS-20	Turk Expense Removal (24) Adj. No. IS-21	Grid Assurance (25) Adj. No. IS-22	EEI (26) Adj. No. IS-23	Advertising (27) Adj. No. IS-24	Customer Account Processing Expense (28) Adj. No. IS-25	Income Tax (29) Adj. No. IS-26	(30) TOTAL ADJUSTMENTS (a) (A)	Test Year End 12/31/18	Pro forma Year
5640	Underground Line Expenses								0	0.00	0.00
5650	Trnsmssion of Elect by Others			215,230					9,467,359	96,418,756.26	105,886,115.26
5660	Misc Transmission Expenses		105						331,540	1,628,477.90	1,960,017.90
5670	Rents								0	36,806.28	36,806.28
		0	**105**	**215,230**	**0**	**0**	**0**	**0**	**9,823,902**	**120,834,284.22**	**130,658,186.22**
	Transmission Maintenance										
5680	Maint Supv & Engineering								130	41,077.34	41,207.34
5690	Maintenance of Structures								347	80,838.40	81,185.40
5691	Maintenance of Structures								966	3,946.21	4,912.21
5692	Maintenance of Structures								(4,149)	451,796.67	447,647.67
5693	Maintenance of Structures								0	40,412.21	40,412.21
5700	Maint of Station Equipment								(68,662)	3,594,257.68	3,525,595.68
5710	Maintenance of Overhead Lines								15,698	10,328,800.36	10,344,498.36
5720	Maint of Underground Lines								202	749.63	951.63
5730	Maint of Misc Trnsmssion Plt								439	38,034.19	38,473.19
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(55,029)**	**14,579,912.69**	**14,524,883.69**
	Regional Market Expenses - O										
5757	SPP Admin-MAM&SC								0	1,514,935.66	1,514,935.66
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1,514,935.66**	**1,514,935.66**
	Distribution Expenses - Opera										
5800	Oper Supervision & Engineering								(70,811)	2,454,445.36	2,383,634.36
5810	Load Dispatching								0	31,526.71	31,526.71
5820	Station Expenses								23,247	403,171.65	426,418.65
5830	Overhead Line Expenses								(41,165)	3,146,045.66	3,104,880.66
5840	Underground Line Expenses								(13,506)	2,141,965.94	2,128,459.94
5850	Street Lighting & Signal Sys E								(792)	202,449.76	201,657.76
5860	Meter Expenses								(71,788)	3,518,815.47	3,447,027.47
5870	Customer Installations Exp								(4,266)	722,019.25	717,753.25
5880	Miscellaneous Distribution Exp								85,898	19,094,222.97	19,180,120.97
5890	Rents								0	891,781.89	891,781.89
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(93,183)**	**32,606,444.66**	**32,513,261.66**
	Distribution Expenses - Mainte										
5900	Maint Supv & Engineering								(859)	369,094.99	368,235.99
5910	Maintenance of Structures								(56)	22,518.99	22,462.99
5920	Maint of Station Equipment								16,157	664,100.37	680,257.37
5930	Maintenance of Overhead Lines								2,962,479	47,796,945.60	50,759,424.60
5940	Maint of Underground Lines								(6,810)	1,021,214.16	1,014,404.16
5950	Maint of Lne Trnf,Rglators&Dvi								(1,789)	140,319.56	138,530.56
5960	Maint of Strt Lghtng & Sgnal S								(3,388)	392,933.14	389,545.14
5970	Maintenance of Meters								(3,923)	478,154.96	474,231.96
5980	Maint of Misc Distribution Plt								(1,651)	245,998.03	244,347.03
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**2,960,160**	**51,131,279.80**	**54,091,439.80**
	Cust. Accts . Expense										
9010	Supervision - Customer Accts								13,305	667,240.18	680,545.18

Supporting Schedules:
(a) WP C 2-1 - WP C 2-26

Recap Schedules:
(A) Schedule C-1

Southwestern Electric Power Company
Adjustments to Test Year Statement of U
Test Year Ending December 31, 2018
Docket No. 19-008-U

(1) FERC ACCT.NO.	(2) DESCRIPTION	LA Deferred Fuel (23) Adj. No. IS-20	Turk Expense Removal (24) Adj. No. IS-21	Grid Assurance (25) Adj. No. IS-22	EEI (26) Adj. No. IS-23	Advertising (27) Adj. No. IS-24	Customer Account Processing Expense (28) Adj. No. IS-25	Income Tax (29) Adj. No. IS-26	(30) TOTAL ADJUSTMENTS (a) (A)	Test Year End 12/31/18	Pro forma Year
9020	Meter Reading Expenses								(11,360)	2,161,177.58	2,149,817.58
9030	Cust Records & Collection Exp						277,929		917,002	15,864,704.71	16,781,706.71
9040	Uncollectible Accounts								3,133,882	(525,204.90)	2,608,677.10
9050	Misc Customer Accounts Exp								(41,101)	146,806.02	105,705.02
	Total	**0**	**0**	**0**	**0**	**0**	**277,929**	**0**	**4,011,728**	**18,314,723.59**	**22,326,451.59**
	Customer Serv. And Informatic										
9070	Supervision - Customer Service								(6,752,254)	7,447,114.45	694,860.45
9080	Customer Assistance Expenses	(401)							(11,453,812)	13,861,625.86	2,407,813.86
9090	Information & Instruct Advrtis								0	14,452.99	14,452.99
9100	Misc Cust Svc&Informational Ex								1,623	6,921.60	8,544.60
9110	Supervision - Sales Expenses								0	321.35	321.35
	Total	**(401)**	**0**	**0**	**0**	**0**	**0**	**0**	**(18,204,443)**	**21,330,436.25**	**3,125,993.25**
	Sales Expense										
9120	Demonstrating & Selling Exp								87	166,232.82	166,319.82
9130	Advertising Exp					(22,410)			(22,410)	0.00	(22,410.00)
	Total	**0**	**0**	**0**	**0**	**(22,410)**	**0**	**0**	**(22,323)**	**166,232.82**	**143,909.82**
	Admin. and General Exp. - Ope										
9200	Administrative & Gen Salaries		(31,588)						1,884,312	32,439,794.20	34,324,106.20
9210	Office Supplies and Expenses		(65)						(446,550)	2,945,643.50	2,499,093.50
9220	Administrative Exp Trnsf - Cr								(13,221)	(3,671,698.55)	(3,684,919.55)
9230	Outside Services Employed		(8,300)						(8,151)	17,651,884.46	17,643,733.46
9240	Property Insurance		(481,927)						(481,927)	2,605,012.40	2,123,085.40
9250	Injuries and Damages		(294,078)						(284,653)	4,602,159.26	4,317,506.26
9260	Employee Pensions & Benefits		(680,719)						(663,286)	10,652,883.10	9,989,597.10
9270	Franchise Requirements								0	0.00	0.00
9280	Regulatory Commission Exp								222,109	2,958,133.84	3,180,242.84
9301	General Advertising Expenses								6,117	258,799.38	264,916.38
9302	Misc General Expenses				(49)				397,153	1,281,951.83	1,679,104.83
9310	Rents								0	896,504.58	896,504.58
	Total	**0**	**(1,496,677)**	**0**	**(49)**	**0**	**0**	**0**	**611,903**	**72,621,068.00**	**73,232,971.00**
	Maintenance of General Plant										
9350	Maintenance of General Plant								(75,718)	6,345,561.85	6,269,843.85
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(75,718)**	**6,345,561.85**	**6,269,843.85**
	Total O&M Expense	**(4,038,423)**	**(16,553,436)**	**215,230**	**(49)**	**(22,410)**	**277,929**	**0**	**(687,500,336)**	**1,185,555,011.42**	**498,054,675.42**
	Depreciation and Amortization										
4030	Depreciation Expense								(5,254,253)	221,748,294.96	216,494,041.96
4031	Depr - Asset Retirement Oblig								0	1,474,281.18	1,474,281.18
4037	Depreciation Expense								0	(1,762,559.16)	(1,762,559.16)
4040	Amortization of Plant								0	17,638,899.11	17,638,899.11
4073	Regulatory Debits								(1,713,791)	2,673,307.49	959,516.49
4074	Regulatory Credits								0	(72,000.00)	(72,000.00)
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(6,968,044)**	**241,700,223.58**	**234,732,179.58**

Supporting Schedules:
(a) WP C 2-1 - WP C 2-26

Recap Schedules:
(A) Schedule C-1

Southwestern Electric Power Company
Adjustments to Test Year Statement of U
Test Year Ending December 31, 2018
Docket No. 19-008-U

(1) FERC ACCT.NO.	(2) DESCRIPTION	LA Deferred Fuel (23) Adj. No. IS-20	Turk Expense Removal (24) Adj. No. IS-21	Grid Assurance (25) Adj. No. IS-22	EEI (26) Adj. No. IS-23	Advertising (27) Adj. No. IS-24	Customer Account Processing Expense (28) Adj. No. IS-25	Income Tax (29) Adj. No. IS-26	(30) TOTAL ADJUSTMENTS (a) (A)	Test Year End 12/31/18	Pro forma Year
	Taxes Other Than Income Taxe										
4081002	FICA								25,860	10,876,194.44	10,902,054.44
4081003	Federal Unemployment Tax								0	58,748.35	58,748.35
408100515	Real Personal Property Taxes								0	0.00	0.00
408100516	Real Personal Property Taxes								0	0.00	0.00
408100517	Real Personal Property Taxes								911,696	(911,696.28)	(0.28)
408100518	Real Personal Property Taxes								(64,201,415)	64,201,415.33	0.33
408100519	Real Personal Property Taxes								62,177,492	0.00	62,177,492.00
408100615	State Gross Receipts Tax								0	0.00	0.00
408100616	State Gross Receipts Tax								0	2.00	2.00
408100617	State Gross Receipts Tax								(2)	6,037,591.19	6,037,589.19
408100618	State Gross Receipts Tax								(104)	79,692.21	79,588.21
4081007	State Unemployment Tax								0	0.00	0.00
408100815	State Franchise Taxes								0	0.00	0.00
408100816	State Franchise Taxes								0		0.00
408100818	State Franchise Taxes								0	5,165,950.96	5,165,950.96
408101415	Federal Excise Taxes								0	0.00	0.00
408101416	Federal Excise Taxes								0		0.00
408101417	Federal Excise Taxes								0	517.92	517.92
408101418	Federal Excise Taxes								0	406.74	406.74
408101716	St Lic-Rgstrtion Tax-Fees								0	0.00	0.00
408101717	St Lic-Rgstrtion Tax-Fees								0	14,575.00	14,575.00
408101718	St Lic-Rgstrtion Tax-Fees								0	17,070.00	17,070.00
408101815	St Publ Serv Comm Tax-Fees								0	0.00	0.00
408101816	St Publ Serv Comm Tax-Fees								0	0.00	0.00
408101817	St Publ Serv Comm Tax-Fees								0	731,124.61	731,124.61
408101818	St Publ Serv Comm Tax-Fees								0	1,252,713.72	1,252,713.72
408101900	State Sales and Use Taxes								311,500	(311,500.00)	0.00
408101914	State Sales and Use Taxes								0	0.00	0.00
408101915	State Sales and Use Taxes								0	0.00	0.00
408101916	State Sales and Use Taxes								(185,277)	185,276.60	(0.40)
408101917	State Sales and Use Taxes								(246)	245.80	(0.20)
408101918	State Sales and Use Taxes								(4,876)	4,875.82	(0.18)
408102216	Municipal License Fees								0	0.00	0.00
408102217	Municipal License Fees								0	0.00	0.00
408102218	Municipal License Fees								0	80,475.00	80,475.00
408102316	Local Privilege-Franchise Tax								0	0.00	0.00
408102317	Local Privilege-Franchise Tax								0	0.00	0.00
408102318	Local Privilege-Franchise Tax								0	18,005,587.28	18,005,587.28
408102716	Misc State and Local Taxes								0	0.00	0.00
408102915	Real-Pers Prop Tax-Cap Leases								0	0.00	0.00
408102916	Real-Pers Prop Tax-Cap Leases								0	0.00	0.00
408102917	Real-Pers Prop Tax-Cap Leases								(9,469)	9,468.86	(0.14)
408102918	Real-Pers Prop Tax-Cap Leases								0	143,834.00	143,834.00
4081033	Fringe Benefit Loading - FICA								0	(3,379,244.19)	(3,379,244.19)
4081034	Fringe Benefit Loading - FUT								0	(19,508.46)	(19,508.46)
4081035	Fringe Benefit Loading - SUT								0	(30,556.71)	(30,556.71)
	Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(974,841)**	**102,213,260.19**	**101,238,419.19**

Supporting Schedules:
(a) WP C 2-1 - WP C 2-26

Recap Schedules:
(A) Schedule C-1

Southwestern Electric Power Company
Adjustments to Test Year Statement of U
Test Year Ending December 31, 2018
Docket No. 19-008-U

(1) FERC ACCT.NO.	(2) DESCRIPTION	LA Deferred Fuel (23) Adj. No. IS-20	Turk Expense Removal (24) Adj. No. IS-21	Grid Assurance (25) Adj. No. IS-22	EEI (26) Adj. No. IS-23	Advertising (27) Adj. No. IS-24	Customer Account Processing Expense (28) Adj. No. IS-25	Income Tax (29) Adj. No. IS-26	(30) TOTAL ADJUSTMENTS (a) (A)	Test Year End 12/31/18	Pro forma Year
	Other Provisions										
4111	Accretion expense								0	2,558,193.25	2,558,193.25
4118	Gain Disposition of Allowances								0	619,127.29	619,127.29
		0	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**3,177,320.54**	**3,177,320.54**
	TOTAL EXPENSES	**(4,038,423)**	**(16,553,436)**	**215,230**	**(49)**	**(22,410)**	**277,929**	**0**	**(695,443,221)**	**1,532,645,815.73**	**837,202,594.73**
	OPERATING INCOME BEFORE	**4,038,423**	**16,553,436**	**(215,230)**	**49**	**22,410**	**(277,929)**	**0**	**(35,395,678)**	**298,558,363.74**	**263,162,685.74**
	Income Taxes										
4091	FIT -current							(2,093,009)	(2,093,009)	22,913,183.18	20,820,174.18
4091002	SIT - current							(1,384,442)	(1,384,442)	4,518,352.21	3,133,910.21
4092	Income Tax, Oth Inc & Ded								0		0.00
	Current	**0**	**0**	**0**	**0**	**0**	**0**	**(3,477,451)**	**(3,477,451)**	**27,431,535.39**	**23,954,084.39**
4101	Prov Def Inc Tax, Util Oper In							(790,208,555)	(790,208,555)	777,092,760.27	(13,115,794.73)
4102	Prov Def I/T Oth Inc & Ded								0		0.00
	Provision for Deferred	**0**	**0**	**0**	**0**	**0**	**0**	**(790,208,555)**	**(790,208,555)**	**777,092,760.27**	**(13,115,794.73)**
4111	Prov Def I/T-Cr Util Oper Inc							783,738,050	783,738,050	(783,738,049.89)	0.11
4112	Prv Def I/T-Cr Oth I&D								0		0.00
4114	ITC Adj, Utility Operations							857,639	857,639	(1,244,396.00)	(386,757.00)
	Writeback of Deferred	**0**	**0**	**0**	**0**	**0**	**0**	**784,595,689**	**784,595,689**	**(784,982,445.89)**	**(386,756.89)**
	Total Income Tax expense	**0**	**0**	**0**	**0**	**0**	**0**	**(9,090,317)**	**(9,090,317)**	**19,541,849.77**	**10,451,532.77**
	Rounding										**3.00**
	UTILITY OPERATING INCOME	**4,038,423**	**16,553,436**	**(215,230)**	**49**	**22,410**	**(277,929)**	**9,090,317**	**(26,305,361)**	**279,016,513.97**	**252,711,155.97**

Supporting Schedules:
(a) WP C 2-1 - WP C 2-26

Recap Schedules:
(A) Schedule C-1

Southwestern Electric Power Company **WP C 2-1**
Pro Forma Adjustment - Payroll Test Year End
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Description	FERC Account	Total Payroll	Projected TY Payroll	Adjustment (A)
1	Payroll Adjustment - Excluding Turk	500	3,498,998	3,545,024	46,026
2		501	3,194,314	3,236,332	42,018
3		502	4,327,357	4,384,279	56,922
4		505	3,728,105	3,777,145	49,040
5		506	6,607,081	6,693,991	86,910
6		510	1,981,611	2,007,677	26,066
7		511	405,565	410,900	5,335
8		512	12,146,690	12,306,468	159,778
9		513	807,864	818,491	10,627
10		514	654,993	663,608	8,615
11		548	325,224	329,502	4,278
12		553	174,719	177,017	2,298
13		560	882,460	894,068	11,608
14		561.2	416,296	421,772	5,476
15		562	105,740	107,131	1,391
16		563	58,312	59,079	767
17		566	182,262	184,659	2,397
18		568	23,700	24,012	312
19		569	7,186	7,280	94
20		570	2,076,742	2,104,060	27,318
21		571	470,986	477,181	6,195
22		573	80	81	1
23		580	657,627	666,277	8,650
24		582	117,072	118,612	1,540
25		583	1,283,197	1,300,076	16,879
26		584	1,411,214	1,429,777	18,563
27		585	77,475	78,494	1,019
28		586	2,600,700	2,634,909	34,209
29		587	442,736	448,560	5,824
30		588	9,007,943	9,126,434	118,491
31		590	281,212	284,911	3,699
32		591	3,412	3,456	44
33		592	254,813	258,164	3,351
34		593	6,265,586	6,348,004	82,418
35		594	533,079	540,091	7,012
36		595	43,941	44,519	578
37		596	252,609	255,932	3,323
38		597	386,615	391,700	5,085
39		598	160,172	162,279	2,107
40		901	490,682	497,136	6,454
41		902	1,409,641	1,428,184	18,543
42		903	2,330,611	2,361,268	30,657
43		907	1,080,278	1,094,488	14,210
44		908	2,293,715	2,323,886	30,171
45		920	4,600,419	4,660,933	60,514
46		921	9,768	9,897	129
47		922	(1,004,375)	(1,017,587)	(13,212)
48		925	137,353	139,159	1,806
49		928	494	500	6
50		930.2	44,064	44,643	579
51		935	1,494,299	1,513,958	19,659
52	**Pro Forma Adjustment for Payroll - Increase to Operating Expenses**		**78,742,637**	**79,778,417**	**1,035,780**

Additional supporting files provided electronically.
PURPOSE:
To increase operating expenses for payroll based on YE employees and the 2019 scheduled increase of 3.5%.

Recap Schedule
(A) Schedule C-2

Southwestern Electric Power Company **WP C 2-2**
Pro Forma Adjustment - Employee Incentives
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Description	FERC Account	Total Annual Incentive	Projected TY Annual Incentive	Adjustment (A)
1	Annual Incentive Plans - excludes Turk	500	315,834	238,963	(76,871)
2		501	371,083	279,192	(91,891)
3		502	534,617	402,230	(132,387)
4		505	625,719	470,773	(154,946)
5		506	624,550	469,893	(154,657)
6		510	148,776	111,935	(36,841)
7		511	49,724	37,411	(12,313)
8		512	1,351,794	1,017,026	(334,768)
9		513	98,338	74,030	(24,308)
10		514	84,813	63,856	(20,957)
11		548	28,131	21,165	(6,966)
12		553	17,999	13,548	(4,451)
13		560	114,440	93,449	(20,991)
14		561	29,943	24,498	(5,445)
15		562	19,162	15,684	(3,478)
16		563	6,704	5,489	(1,215)
17		566	20,588	16,733	(3,855)
18		568	2,269	1,856	(413)
19		561.2	1,008	824	(184)
20		570	180,960	148,088	(32,872)
21		571	38,609	32,636	(5,973)
22		573	11	9	(2)
23		580	69,250	54,240	(15,010)
24		582	16,099	13,172	(2,927)
25		583	234,389	193,373	(41,016)
26		584	122,044	100,337	(21,707)
27		585	6,966	5,747	(1,219)
28		586	325,771	267,577	(58,194)
29		587	41,113	33,920	(7,193)
30		588	956,622	782,981	(173,641)
31		590	25,330	21,110	(4,220)
32		591	533	436	(97)
33		592	35,134	28,747	(6,387)
34		593	1,091,851	906,015	(185,836)
35		594	49,479	40,825	(8,654)
36		595	11,362	9,374	(1,988)
37		596	28,082	23,169	(4,913)
38		597	36,811	30,471	(6,340)
39		598	17,282	14,258	(3,024)
40		901	46,801	38,613	(8,188)
41		902	139,896	115,419	(24,477)
42		903	225,776	186,273	(39,503)
43		907	96,200	79,368	(16,832)
44		908	210,362	173,555	(36,807)
45		920	3,258,345	675,236	(2,583,109)
46		921	1,576	1,300	(276)
47		925	15,241	12,512	(2,729)
48		928	50	41	(9)
49		930.2	4,631	3,735	(896)
50		935	137,739	15,898	(121,841)
51	**Pro Forma Adjustment for Payroll - Decrease to Operating Expenses**		**$ 11,869,807**	**$ 7,366,990**	**$ (4,502,817)**

Southwestern Electric Power Company **WP C 2-2**
Pro Forma Adjustment - Employee Incentives
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Description	FERC Account	Total Annual Incentive	Projected TY Annual Incentive	Adjustment (A)
52	Long Term Incentive Plans - excludes Turk	5000	16,345	4,086	(12,259)
53		5010	21,708	6,504	(15,204)
54		5020	17,955	2,335	(15,620)
55		5050	22,199	4,427	(17,772)
56		5060	44,460	14,676	(29,784)
57		5100	879	(1,361)	(2,240)
58		5110	1,462	(44)	(1,506)
59		5120	99,414	32,757	(66,657)
60		5130	2,552	(90)	(2,642)
61		5140	4,363	865	(3,498)
62		5480	2,079	684	(1,395)
63		5530	396	5	(391)
64		5600	793	(14)	(807)
65		5620	170	14	(156)
66		5630	200	54	(146)
67		5660	94	(6)	(100)
68		5680	16	(1)	(17)
69		5690	11	2	(9)
70		5700	549	(40)	(589)
71		5710	124	(8)	(132)
72		5730	-	-	-
73		5800	3,851	924	(2,927)
74		5820	91	(6)	(97)
75		5830	26,429	7,521	(18,908)
76		5840	14,270	4,333	(9,937)
77		5850	883	291	(592)
78		5860	31,185	7,798	(23,387)
79		5870	4,088	1,191	(2,897)
80		5880	83,556	18,483	(65,073)
81		5900	3,725	1,117	(2,608)
82		5910	3	-	(3)
83		5920	295	20	(275)
84		5930	97,384	21,104	(76,280)
85		5940	7,708	2,540	(5,168)
86		5950	339	(40)	(379)
87		5960	2,152	354	(1,798)
88		5970	3,712	937	(2,775)
89		5980	870	131	(739)
90		9010	4,471	975	(3,496)
91		9020	10,998	2,463	(8,535)
92		9030	19,950	4,331	(15,619)
93		9070	6,967	1,636	(5,331)
94		9080	20,779	5,468	(15,311)
95		9200	(6,674,307)	672,709	7,347,016
96		9210	48	(3)	(51)
97		9250	302	99	(203)
98		9280	5	-	(5)
99		9302	27	(4)	(31)
100	**Pro Forma Adjustment for Payroll - Increase to Operating Expenses**		**$ (6,094,450)**	**$ 819,217**	**$ 6,913,667**
					$ 2,410,850

Additional supporting files provided electronically.

PURPOSE:
To adjust operating expenses for employee incentives based on a target level.

Recap Schedule
(A) Schedule C-2

Southwestern Electric Power Company
Pro Forma Adjustment - FICA
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Description	FERC Account			Amount
1	FICA Adjustment for Base Payroll				
2	SWEPCO payroll proforma adjustment		(a)	$	1,035,780
3	Weighted average FICA rate applied to base pay for the period Jan - Jul 2018				7.387%
4	Adjustment to FICA expense related to payroll proforma adjustment			$	76,513
5	SWEPCO annual incentive plan proforma adjustment		(b)	$	(4,502,817)
6	Weighted average FICA rate applied to annual incentive plan payments for the period Jan - Jul 2018				7.351%
7	Adjustment to FICA expense related to annual incentive plan proforma adjustment			$	(331,002)
8	SWEPCO long-term incentive plan proforma adjustment		(b)	$	6,913,667
9	Weighted average FICA rate applied to long-term incentive payments for the period Jan - Jul 2018				4.055%
10	Adjustment to FICA expense related to long-term incentive proforma adjustment			$	280,349
11	**Total FICA expense adjustment**	408.1		$	25,860
	Pro Forma Adjustment by FERC account				
12	Account 408.1 Increase (Decrease)			$	25,860

PURPOSE: To adjust FICA expense consistent with base payroll and incentive payroll adjustments. The discussion of this adjustment can be found in the testimony of Mr. Jason Yoder.

Supporting Schedules and Workpapers:
(a) WP C 2-1
(b) WP C 2-2

Recap Schedules:
(A) Schedule C-2

Southwestern Electric Power Company **WP C 2-4**
Pro Forma Adjustment - Credit Line Fees
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Description	Account		Increase (Decrease) (A)
1	Other Interest Expense	4310007	(a)	(390,220)
2	A&G expense	930.2		390,220
				0

Purpose: To reclassify credit line fees to A&G expense

Supporting Schedules:
(a) Schedule E-17A

Recap Schedules:
(A) Schedule C-2

Southwestern Electric Power Company
Pro Forma Adjustemnt - Arkansas Rate Case Expense
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP C 2-5

Timing of Activities	Catering and/or Business Meals	Consulting (1)	Newspaper Notice	Employee Travel Expenses	Outside Legal Expenses (2)	Postage & Fed Ex	Printing	Delivery	Other (Parking- Air-rooms-transcripts)	Temporary Employees	Total	
Case Preparation	$15,000	$340,000	$25,000	$50,000	$500,000	$0	$0	$0	$25,000	$130,000	$1,085,000	
Rate Case Audit											0	
Finalizing/Production											0	
RFI's						0					0	
Witness Preparation											0	
Rebuttal/Intervenor Testimony						0						
Hearings											0	
Legal Briefing/PFD/Rate Exp.											0	
	$15,000	**$340,000**	**$25,000**	**$50,000**	**$500,000**	**$0**	**$0**	**$0**	**$25,000**	**$130,000**	**$1,085,000**	**(A)**

(1) ROE (90,000), Dolet Hills (250,000)

(2) Matthews (150,000), Cuffman (350,000)

Amortization Period	2
Expense Amount (407)	$542,500

Purpose: To include amount estimated for timing and flow of rate case expense

Recap Schedules:
(A) Schedule C-2

Southwestern Electric Power Company **WP C 2-6**
Pro Forma Adjustment - Energry Efficiency Removal
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Description	FERC Account	TY 2018 Amount	Projected Portion of TY Amount		Amount	
1	Remove expenses related to SWEPCO Energy Efficiency Riders	907	$ (3,777,092)	$ (2,844,982)	$	(6,622,074)	
2	Remove expenses related to SWEPCO Energy Efficiency Riders	908	$ (7,290,813)	$ (4,426,407)	$	(11,717,220)	
3	Pro Forma Adjustment				**$**	**(18,339,294)**	(A)
	Additional supporting files provided electronically.						

PURPOSE:
To remove expenses related to the Energy Efficiency Program Rider that are being recovered in the Arkansas Jurisdiction only

Recap Schedules:
(A) Schedule C-2

Southwestern Electric Power Company **WP C 2-7**
Pro Forma Adjustment- Fuel and Purchase Power Removal
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Description	FERC Account	Amount
1	Fuel (501)	501	$ (472,530,027)
2	Fuel (547)	547	(19,001,320)
3	Purchased Power	555	(171,126,607)
4	Consumables Recovered in FAC	502	(4,136,116)
5	Consumables Recovered in FAC	509	(29,861)
7	**Pro Forma Adjustment # 7**		**$ (666,823,931)** (A)

PURPOSE:
To remove all fuel expenses from the revenue requirement.

Recap Schedules:
(A) Schedule C-2

Southwestern Electric Power Company
Fuel and Purchase Power Removal Support
Test Year Ending December 31, 2018
Docket No. 19-008-U

	Fuel - Acct 501/547(a)			**Actual** Jan-18	**Actual** Feb-18	**Actual** Mar-18	**Actual** Apr-18	**Actual** May-18	**Actual** Jun-18	**Actual** Jul-18	**Budget** Aug-18	**Budget** Sep-18
5010000	Fuel	5010000	Non Elig	353,890.25	410,315.72	308,116.18	444,792.80	627,289.64	288,406.72	349,491.36	335,953.00	335,960.00
5010001	Fuel Consumed	5010001		20,484,274	14,277,651	13,179,546	13,686,159	8,961,172	18,385,237	20,443,965	18,431,665.00	17,215,059.00
5010003	Fuel - Procure Unload & Handle	5010003	Non Elig	1,087,951	617,986	685,637	619,373	580,930	1,089,942	1,085,249	1,188,158.00	1,087,436.00
5010012	Ash Sales Proceeds	5010012	Non Elig	(372,258)	(365,960)	(556,986)	(319,697)	(463,282)	(570,309)	(599,507)	(451,392)	(426,768)
5010013	Fuel Survey Activity	5010013		159,262	159,324	160,339	(154,105)	(307,098)	(307,098)	(307,098)	(100,477)	(93,845)
5010018	Lignite Consumed	5010018		19,547,643	19,956,264	12,017,528	3,366,014	14,962,831	19,945,532	17,316,065	18,424,649	16,768,881
5010019	Fuel Oil Consumed	5010019		70,888	136,100	187,641	81,570	468,305	121,906	108,569	181,198	105,212
5010020	Nat Gas Consumed Steam	5010020		4,074,826	1,446,986	1,311,730	1,664,281	3,215,879	3,688,611	5,906,374	3,629,354	1,161,566
5010021	Transp Gas Consumed Steam	5010021		184,202	252,252	150,931	118,498	341,562	292,593	464,230	-	-
5010034	Gas Transp Res Fees-Steam	5010034		80,680	(91,744)	(4,858)	147,501	(14,791)	94,973	341,229	2,500	2,500
5010035	Gas Transp Res Fees - CC	5010035		532,731	474,399	529,170	512,100	544,183	497,087	529,170	529,170	512,100
5010036	Nat Gas Consumed CC	5010036		8,878,361	5,288,038	5,320,626	4,068,905	5,830,469	6,449,885	6,343,438	6,006,656	5,818,090
5010037	Transportation Gas CC	5010037	(2)	21,454	30,237	20,487	7,370	23,505	37,252	21,391	-	23,334
5470001	Fuel - Gas Turbine	5010037		351,245	43,436	1,318	159,313	446,838	134,067	344,000	433,782	242,165
5470003	Gas Transp Res Fees - CT			2,450,793	170,486	1,455,875	1,282,131	1,227,648	1,210,186	829,512	1,587,750	1,587,750
5470005	Gas Transp Fees - CT			31,643	1	-	28,113	111,130	25,762	83,127	-	-
502/509	Limestone, Nox, So2 Expense AC 502		(1)	147,173	392,556	339,362	132,001	376,451	530,559	494,633	344,676	344,676
5090013	CSAPR Seasonal NOx Cons. Exp		(1)					1,767	4,699	4,733	3,733	3,733
				58,084,758	43,198,328	35,106,462	25,844,320	36,934,788	51,919,291	53,758,571	50,547,375	44,687,849
Less Merchant Fuel			(1)	955,321	853,147	949,090	834,037	177,223	979,021	1,010,841	822,668	822,668
Less Non-ECR Fuel:												
5010000	Fuel/AEPSC Admin Charge	Non-ECR	Non Elig	353,890	410,316	308,116	444,793	627,290	288,407	349,491	335,953	335,960
5010003	Fuel - Procure Unload & Handle/Welsh Fly Ash Handling	Non-ECR	Non Elig	1,087,951	617,986	685,637	619,373	580,930	1,089,942	1,085,249	1,188,158	1,087,436
5010012	Ash Sales Proceeds		Non Elig	(372,258)	(365,960)	(556,986)	(319,697)	(463,282)	(570,309)	(599,507)	(451,392)	(426,768)
	Turk-Alliance, Depreciation and Lease			67,596	156,002	133,117	153,889	45,028	21,151	120,060	99,549	99,549
	Turk Survey			(128,162)	(128,162)	(128,162)	(128,162)			-		
	Total Non-Eligible Fuel			1,009,017	690,182	441,722	770,196	789,966	829,191	955,293	1,172,268	1,096,177
	Total ECR Fuel Expense			56,120,420	41,655,000	33,715,650	24,240,087	35,967,599	50,111,079	51,792,437	48,552,439	42,769,004

Purchased Power - Account 555

Account	Desc	Category	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18
5550001	Purch Pwr-NonTrading-Nonassoc		6,394,708.63	2,403,256.43	3,776,767.95	7,621,810.42	16,394,317.52	6,964,853.95	8,319,886.20	6,824,733.00	5,093,122.00
5550003	Purchased Power - Cogeneration		16,559.93	18,743.35	12,821.32	9,829.48	27,761.16	30,775.94	24,698.15	-	-
5550023	Purch Power Capacity -NA	Non ECR	759,420.34	755,848.30	752,563.21	752,571.00	752,600.44	752,600.17	752,600.12	874,600.00	874,600.00

Southwestern Electric Power Company
Fuel and Purchase Power Removal Support
Test Year Ending December 31, 2018
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5550024	Purchase Power ERCOT		825.77	170.35	-	1.48	(0.66)	7.05	(0.01)	-	-
5550026	Purchase Power - Fuel - ERCOT		89,859.95	64,869.45	90,959.51	35,429.40	9.65	91,572.09	51,321.58	-	-
5550032	Gas-Conversion-Mone Plant		2.70	(17.43)	-	-	-	-	-	-	-
5550047	Purchase Power Wind Energy		7,086,810.19	6,031,175.65	6,530,845.35	6,899,117.60	6,007,873.38	6,614,130.18	3,057,388.25	4,195,413.00	4,921,763.00
5550054	Purch Power ERCOT-Non-ded		(3,692.59)	0.02	-	0.01	1,272.46	-	10.15	-	-
5550066	SPP Rev. Neutrality Ded-Purch		1,425,803.19	229,363.06	(114,610.84)	344,958.87	367,339.03	636,200.37	313,596.38	-	-
5550113	Cleco PP for Valley - Other	Non ECR	-	-	-	-	-	-	-	-	-
5550128	SPP Net Purch that serve OSS		2,129,688.04	2,733,581.48	1,348,200.40	1,593,371.47	1,047,347.46	2,558,061.22	2,692,965.18	-	-
5550130	SPP Net Marginal Losses LSE		1,086,463.91	445,751.08	446,747.48	347,560.22	167,733.15	370,487.26	(262,478.12)	400,000.00	250,000.00
5550131	SPP Congestion Costs LSE		2,358,218.43	1,874,839.39	522,217.32	3,234,873.05	492,121.78	136,833.08	604,263.71	1,500,000.00	1,500,000.00
5550133	SPP TCR's & ARR's LSE		(1,164,542.34)	(766,735.30)	1,119.41	1,511,524.42	2,416,754.84	(10,482,589.06)	(935,588.79)	(1,250,000.00)	(2,000,000.00)
5550136	SPP Net Make Whole Payment LSE		761,994.56	248,587.47	182,025.84	186,048.41	255,149.51	280,734.01	301,725.28	275,000.00	300,000.00
5550138	SPP Net Make Whole Payment LSE		(557,623.62)	(91,925.24)	(182,891.93)	(211,859.76)	(232,911.20)	(290,718.86)	(629,181.38)	(150,000.00)	(300,000.00)
5550320	SPP Net Regulation LSE		253,391.78	200,627.78	240,166.63	152,046.08	213,390.34	295,513.34	256,699.23	100,000.00	150,000.00
5550321	SPP Net Spinning Reserve LSE		178,708.11	121,327.50	33,299.49	43,294.48	42,240.89	75,744.07	125,799.02	75,000.00	50,000.00
5550324	SPP Net Supp Reserve LSE		48,964.99	28,891.60	24,661.05	16,620.38	51,551.35	56,006.34	128,130.27	20,000.00	20,000.00
5550325	SPP Contingency Costs LSE		6,178.20	3,385.40	44,340.70	5,661.74	(3,994.86)	(2,192.91)	2,661.67	5,000.00	5,000.00
Grand Total			20,871,740.17	14,301,740.34	13,709,232.89	22,542,858.75	28,000,556.24	8,088,018.24	14,804,496.89	12,869,746.00	10,864,485.00

Less Non-ECR Purchased Power:

5550023	Purch Power Capacity -NA	Non ECR	(759,420.34)	(755,848.30)	(752,563.21)	(752,571.00)	(752,600.44)	(752,600.17)	(752,600.12)	(754,123.51)	(754,123.51)
		(1)							(660.98)		
			(759,420.34)	(755,848.30)	(752,563.21)	(752,571.00)	(752,600.44)	(752,600.17)	(753,261.10)	(754,123.51)	(754,123.51)
	Total ECR Purchased Power		20,112,319.83	13,545,892.04	12,956,669.68	21,790,287.75	27,247,955.80	7,335,418.07	14,051,896.77	12,115,622.49	10,110,361.49

To

	Recap	
547	19,001,321	(A)
502	4,136,115	(A)
509	29,863	(A)

(1) Sourced from the Company's monthly over/under fuel calculations which results in the annual Arkansas ECR filing.

(2) Budgeted amounts sourced from Company's 6+6 forecast.

Supporting Schedules and Workpapers:

(a) E-17A

Southwestern Electric Power Company
Fuel and Purchase Power Removal Support
Test Year Ending December 31, 2018
Docket No. 19-008-U

	Fuel - Acct 501/547(a)	**Budget** Oct-18	**Budget** Nov-18	**Budget** Dec-18	Total
5010000	Fuel	340,252.00	340,280.00	335,742.00	4,470,490
5010001	Fuel Consumed	14,239,280.00	17,638,583.00	19,739,767.00	196,682,358
5010003	Fuel - Procure Unload & Handle	939,754.00	1,071,888.00	1,128,164.00	11,182,468
5010012	Ash Sales Proceeds	(293,380)	(360,367)	(271,907)	(5,051,813)
5010013	Fuel Survey Activity	(77,623)	(96,154)	(107,608)	(1,072,181)
5010018	Lignite Consumed	15,841,923	13,605,611	11,189,040	182,941,981
5010019	Fuel Oil Consumed	195,411	202,134	137,947	1,996,881
5010020	Nat Gas Consumed Steam	963,747	843,251	818,474	28,725,079
5010021	Transp Gas Consumed Steam	-	-	-	1,804,268
5010034	Gas Transp Res Fees-Steam	2,500	2,500	2,500	565,490
5010035	Gas Transp Res Fees - CC	529,170	512,100	529,170	6,230,550
5010036	Nat Gas Consumed CC	1,013,100	2,671,749	7,294,695	64,984,012
5010037	Transportation Gas CC	4,137	9,102	27,283	225,552
5470001	Fuel - Gas Turbine	-	-	-	2,156,164
5470003	Gas Transp Res Fees - CT	1,587,750	1,587,750	1,587,750	16,565,381
5470005	Gas Transp Fees - CT	-	-	-	279,776
502/509	Limestone, Nox, So2 Expense AC 502	344,676	344,676	344,676	4,136,115
5090013	CSAPR Seasonal NOx Cons. Exp	3,733	3,733	3,733	29,863
		35,634,430	38,376,836	42,759,426	516,852,434
Less Merchant Fuel		822,668	822,668	822,668	9,872,019
					Ineligible
Less Non-ECR Fuel:					
5010000	Fuel/AEPSC Admin Charge	340,252	340,280	335,742	4,470,490
5010003	Fuel - Procure Unload & Handle/Welsh Fly Ash Handling	939,754	1,071,888	1,128,164	11,182,468
5010012	Ash Sales Proceeds	(293,380)	(360,367)	(271,907)	(5,051,813)
	Turk-Alliance, Depreciation and Lease	99,549	99,549	99,549	1,194,588
	Turk Survey				(512,648)
	Total Non-Eligible Fuel	1,086,175	1,151,350	1,291,548	11,283,085
					Ineligible
	Total ECR Fuel Expense	33,725,587	36,402,818	40,645,210	495,697,330
			Total Acct 501 to remove		472,530,031

Purchased Power - Account 555

Account	Desc	Oct-18	Nov-18	Dec-18	Total
5550001	Purch Pwr-NonTrading-Nonassoc	5,520,309.00	2,632,744.00	4,959,964.00	76,906,473.10
5550003	Purchased Power - Cogeneration	-	-	-	141,189.33
5550023	Purch Power Capacity -NA	874,600.00	874,600.00	874,600.00	9,651,203.58

Southwestern Electric Power Company
Fuel and Purchase Power Removal Support
Test Year Ending December 31, 2018
Docket No. 19-008-U

5550024	Purchase Power ERCOT	-	-	-	1,003.98
5550026	Purchase Power - Fuel - ERCOT	-	-	-	424,021.63
5550032	Gas-Conversion-Mone Plant	-	-	-	(14.73)
5550047	Purchase Power Wind Energy	5,265,108.00	6,286,910.00	4,584,380.00	67,480,914.60
5550054	Purch Power ERCOT-Non-ded	-	-	-	(2,409.95)
5550066	SPP Rev. Neutrality Ded-Purch	-	-	-	3,202,650.06
5550113	Cleco PP for Valley - Other	-	-	-	-
5550128	SPP Net Purch that serve OSS	-	-	-	14,103,215.25
5550130	SPP Net Marginal Losses LSE	250,000.00	250,000.00	250,000.00	4,002,264.98
5550131	SPP Congestion Costs LSE	2,500,000.00	2,000,000.00	1,500,000.00	18,223,366.76
5550133	SPP TCR's & ARR's LSE	(2,000,000.00)	(1,250,000.00)	(1,500,000.00)	(17,420,056.82)
5550136	SPP Net Make Whole Payment LSE	300,000.00	250,000.00	200,000.00	3,541,265.08
5550138	SPP Net Make Whole Payment LSE	(500,000.00)	(300,000.00)	(100,000.00)	(3,547,111.99)
5550320	SPP Net Regulation LSE	100,000.00	50,000.00	50,000.00	2,061,835.18
5550321	SPP Net Spinning Reserve LSE	25,000.00	50,000.00	50,000.00	870,413.56
5550324	SPP Net Supp Reserve LSE	20,000.00	20,000.00	20,000.00	454,825.98
5550325	SPP Contingency Costs LSE	5,000.00	5,000.00	5,000.00	81,039.94
Grand Total		12,360,017.00	10,869,254.00	10,893,944.00	180,176,089.52
	Less Non-ECR Purchased Power:				
5550023	Purch Power Capacity -NA	(754,123.51)	(754,123.51)	(754,123.51)	(9,048,821.13)
		(754,123.51)	(754,123.51)	(754,123.51)	(9,049,482.11)
	Total ECR Purchased Power	11,605,893.49	10,115,130.49	10,139,820.49	171,126,607.41
		ıtal AC 555 to remove		(A)	171,126,607.41

Supporting Schedules and Workpapers:

(a) E-17A

Recap Schedule

(A) WP C 2-7

Southwestern Electric Power Company **WP C 2-8**
Pro Forma Adjustment - Regulatory Amortization
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Description	FERC Account		Amount	
1	Amoritizaton (407)	407	$	(2,256,291)	(a)
2	Other Revenues (456)	456		409,254	(a)
3	Misc. Gen Exp (506)	506		(83,182)	(a)
4	Trans Exp (565)	565		(878,004)	(a)
5	Misc. Trans (566)	566		(31,298)	(a)
6	Misc D (588)	588		(124,555)	(a)
7	Maint. Of Ovh (593)	593		3,132,290	(a)
8	A&G (921)	921		(54,121)	(a)
9	**Pro Forma Adjustment # 8**		**$**	**114,093**	(A)

PURPOSE:
To adjust regulatory amortizations to the appropriate going level

Supporting Schedules and Workpapers:
(a) WP C 2-8-1

Recap Schedules:
(A) Schedule C-2

Southwestern Electric Power Company **WP C 2-8-1**
Pro Forma Adjustment - Regulatory Amortization
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Account	Description	Historical Test Year Balance (a)	Projected Test Year Amount (a)	Test Year Amount	Adjustments (A)	
1	4073000	Regulatory Debits	816,101	1,159,435	$ 1,975,536	$ (1,975,536)	1
2	4073016	Welsh Unit 2 Reg Asset Amort	284,097	403,620	$ 687,717	$ (687,717)	2
3	4073017	Welsh U2 ARO Reg Asset Amort	4,153	5,901	$ 10,054	$ (10,054)	3
4	4074000	Regulatory Credits	(42,000)	(30,000)	$ (72,000)	$ 72,000	4
5	506	Misc Gen				$ (83,182)	5, (b)
6	566	Misc Trans				$ (31,298)	5, (b)
7	588	Misc D				$ (124,555)	5, (b)
8	593	Ovh Maint				$ (33,032)	5, (b)
9	921	A&G				$ (54,121)	5, (b)
10	407	Amortization				$ 22,286	6, c
11	456	Other Revenue				$ 409,254	7. (d)
12	565	Trans				$ (878,004)	7. (d)
13	407	Amortization				$ 233,358	8, e
14	593	Ovh Maint				$ 3,165,322	9, (f)
15	407	Amortization				$ 89,372	10, (g)
16				Total Adjustments		**$ 114,093**	
	Recap						
17	407					(2,256,291)	
18	456					409,254	
19	506					(83,182)	
20	565					(878,004)	
21	566					(31,298)	
22	588					(124,555)	
23	593					3,132,290	
24	921					(54,121)	
						114,093	
25				Non Jurisdictional or non ongoing amorticatior		$ (230,923)	
26				Proposed Amortizations		$ 345,016	
27						$ 114,093	

28 Adjustment 1 Remove non ongoing amortization related to transmission projects regulatory asset over the May 2018 - April 2019 recovery period, per FERC ER18-748-001 SPP NTC
29 Adjustment 2 Remove Welsh Unit 2 other jurisdictional amortization
30 Adjustment 3 Remove Welsh Unit 2 ARO other jurisdicitonal amortization
31 Adjustment 4 Remove other jurisdictional regulatory credits
32 Adjustment 5 See WP C 2-8-2 to remove SWEPCO LA FRP - 2011 Test Year amortizations Due Diligence, 2010 Severance, and MCCS Feed Study for 5 years starting March 2013.
33 Adjustment 6 See WP C 2-8-3 for total company amortization of Welsh U2 ARO over 23 years
34 Adjustment 7 See WP C 2-8-4 to remove LA jurisdictional amortization of 2017 SPP costs in excess of 2015 SPP costs for 2017.
35 Adjustment 8 See WP C 2-8-5 for proposed amortization of total company Ash pond ARO
36 Adjustment 9 See WP C 2-8-6 for reversal of non jurisdictional amortization
37 Adjustment 10 See WP C 2-8-7 for proposed amortization of the Arkansas Carbon Capture costs

Supporting Schedules and Workpapers:
(a) Schedule E-17A
(b) WP C 2-8-2
(c) WP C 2-8-3
(d) WP C 2-8-4
(e) WP C 2-8-5
(f) WP C 2-8-6
(g) WP C 2-8-7

Recap Schedules:
(A) WP C 2-8

Southwestern Electric Power Company **WP C 2-8-2**
Pro Forma Adjustment - Non-jurisdictional Amortization Removal
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Account	Period	Year	Amount	Description	Journal ID	Unit
1	5060000	1	2018	29,983.31	SWEPCO LA FRP - 2011 Test Year amortizations Due Diligence, 2010 Severance, and MCCS Feed Study for 5 years starting March 2013.	FCLAFRPAMT	168
2	5060000	1	2018	11,606.95		FCLAFRPAMT	168
3	5060000	2	2018	29,983.24		FCLAFRPAMT	168
4	5060000	2	2018	11,608.85		FCLAFRPAMT	168
5	5660000	1	2018	15,649.03		FCLAFRPAMT	194
6	5660000	2	2018	15,649.00		FCLAFRPAMT	194
7	5880000	1	2018	62,277.48		FCLAFRPAMT	159
8	5880000	2	2018	62,277.35		FCLAFRPAMT	159
9	5930000	1	2018	16,516.01		FCLAFRPAMT	159
10	5930000	2	2018	16,516.02		FCLAFRPAMT	159
11	9210001	1	2018	27,060.68		FCLAFRPAMT	159
12	9210001	2	2018	27,060.62		FCLAFRPAMT	159
13	Total			326,188.54			
14	Recap						
15	506			(83,182.35)	(A)		
16	566			(31,298.03)	(A)		
17	588			(124,554.83)	(A)		
18	593			(33,032.03)	(A)		
19	921			(54,121.30)	(A)		
20	Total			(326,188.54)			

Recap Schedules:
(A) WP C 2-8

Southwestern Electric Power Company **WP C 2-8-3**
Pro Forma Adjustment - Total Company Amortization of U2 Asbestos
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Account	Period	Year	Amount (A)	Description	Journal ID	Unit
1	1823377	5	2016	512,576.79	ADJ WELSH U2 ASBESTOS	OAAAROAJE	168
2	Amortization Period			23			
3	Account 407			22,286			

Recap Schedules:
(A) WP C 2-8

Southwestern Electric Power Company **WP C 2-8-4**
Pro Forma Adjustment - Non-jurisdictional Amortization Removal
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Account	Period	Year	Amount (A)	Description	Journal ID	Unit
1	4561042	8	2018	(81,851)	To amortize LA jurisdictional 2017 SPP costs in excess of 2015 SPP costs for 2017. To be amortized over 4 years beginning August 2018. Based on settlement reached on April 19, 2017. LPSC Docket # U-34200.	FCLAFRP15	168
2	4561042	9	2018	(81,851)		FCLAFRP15	168
3	4561042	10	2018	(81,851)		FCLAFRP15	168
4	4561042	11	2018	(81,851)		FCLAFRP15	168
5	5650052	8	2018	175,601		FCLAFRP15	194
6	5650052	9	2018	175,601		FCLAFRP15	194
7	5650052	10	2018	175,601		FCLAFRP15	159
8	5650052	11	2018	175,601		FCLAFRP15	159
9	4561042	Estimated December		(81,851)			
10	5650052	Estimated December		175,601			
11		Total		468,750.00			
12							
13	Recap:						
14	456			409,254			
15	565			(878,004)			
16	Total			(468,750)			

Recap Schedules:
(A) WP C 2-8

Southwestern Electric Power Company **WP C 2-8-5**
Pro Forma Adjustment - Total Company Amortization of Ash Pond ARO over 23 years
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Account	Period	Year	Amount (A)	Description
1	1823099	7	2018	5,268,598.96	July 2018 Historical balance of ARO
2	Exclude Other jurisdiction Amortizati			98,628	
3	Total Company Balance			5,367,227	
4	Amortization Period - Years			23	
5	Annual 407 amortization			233,358	

Recap Schedules:
(A) WP C 2-8

Southwestern Electric Power Company **WP C 2-8-6**
Pro Forma Adjustment - Non-jurisdictional Amortization Removal
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Account	Period	Year	Sum Amount (A)	Description	Journal ID
1	5930000	various	2018	-2,703,644	Other Jurisdiction Veg Management	VEGETATION
2	5930000	various	2018	(461,678)	Other Jurisdiction Amoritization	CITYMAIN*
3				(3,165,322)		
4	Recap					
5	593			3,165,322		

Recap Schedules:
(A) WP C 2-8

Southwestern Electric Power Company **WP C 2-8-7**
Pro Forma Adjustment - Arkansas Amortization of Carbon Capture over 5 years
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Account	Period	Year	Sum Amount (A)	Description
1	1823306	7	2018	446,859.00	Carbon Capture Regulatory Asset - Direct Assign to Arkansas
2					
3	Arkansas Balance			446,859	
4	Amortization Period			5	
5	Annual 407 amortization			89,372	Direct Assign

Recap Schedules:
(A) WP C 2-8

Southwestern Electric Power Company **WP C 2-9**
Pro Forma Adjustment - Aviation
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Description	FERC Account	Historical 7/31/2018	Proj. Test Year Dec. 31, 2018		Amount (A)
1	Operating Supervision & Engineering	500	175,465	37,264	$	212,729
2	Other Expenses	557	-	6,939	$	6,939
3	Operating Supervision & Engineering	560	35,699	2,885	$	38,584
4	Misc Transmission Expenses	566	12,243	-	$	12,243
5	Operating Supervision & Engineering	580	7,716	-	$	7,716
6	Customer Assistance Expenses	908	7,411	-	$	7,411
7	Salaries	920	-	496,882	$	496,882
8	Office Supplies & Exp - Nonassociated	921	364,293	-	$	364,293
9	Corproate & Fiscal Expenses	930	9,786	-	$	9,786
10	**Pro Forma Adjustment**		612,613	543,970	**$**	**1,156,583**
11	Additional supporting files provided electronically.			**Adjustment**	**$**	**(1,156,583)**

PURPOSE:
To remove all aviation expenses

Recap Schedules:
(A) Schedule C-2

Southwestern Electric Power Company **WP C 2-10**
Pro Forma Adjustment - AEPSC ICP
Test Year Ending December 31, 2018
Docket No. 19-008-U

(Excludes Turk ICP)

(1)	(2)	(3)	(5)	(6)	(7)
			(2) + (3)		(6) - (5)
	Historical	Forecasted	Total	Normalized	Pro forma
Accounts	Test Year	Test Year	Test Year	Test Year	Adjustment (A)
5000	803,295	492,076	1,295,371	1,048,044	(247,327)
5010	56,842	30,932	87,774	69,586	(18,188)
5020	6,538		6,538	4,074	(2,464)
5050	133		133	111	(22)
5060	(391,475)	18,443	(373,033)	41,975	415,008
5100	63,012	74,353	137,365	112,819	(24,546)
5110	14,623		14,623	11,672	(2,951)
5120	71,890	72,655	144,545	123,168	(21,377)
5130	15,015		15,015	10,592	(4,423)
5140	8,609		8,609	5,619	(2,990)
5240	1		1	1	0
5280	432		432	263	(169)
5300	5		5	4	(1)
5350	307		307	164	(143)
5530	528		528	421	(107)
5560	132,189	62,607	194,796	152,151	(42,645)
5570	235,219	165,890	401,109	326,765	(74,344)
5600	329,672	125,432	455,104	357,946	(97,158)
5611	3		3	3	0
5612	49,444	42,064	91,508	76,219	(15,289)
5615	8,180	6,154	14,334	11,970	(2,364)
5616	13		13	4	(9)
5620	282		282	97	(185)
5630	737		737	585	(152)
5660	(189,581)	15,418	(174,163)	50,021	224,184
5680	81		81	64	(17)
5690	44		44	36	(8)
5691	221		221	178	(43)
5692	10,379	5,307	15,686	12,235	(3,451)
5700	6,876	10,169	17,045	14,682	(2,363)
5710	16,600	6,551	23,151	18,017	(5,134)
5720	60		60	38	(22)
5730	150		150	90	(60)
5800	64,991	37,655	102,646	82,071	(20,575)
5820	5,944		5,944	4,081	(1,863)
5830	496		496	394	(102)
5840	852	445	1,297	1,017	(281)
5860	10,379	7,812	18,191	14,769	(3,422)
5880	(157,175)	23,667	(133,508)	68,012	201,520
5900	568		568	373	(195)

Southwestern Electric Power Company **WP C 2-10**
Pro Forma Adjustment - AEPSC ICP
Test Year Ending December 31, 2018
Docket No. 19-008-U

(Excludes Turk ICP)

(1)	(2)	(3)	(5)	(6)	(7)
			(2) + (3)		(6) - (5)
	Historical	Forecasted	Total	Normalized	Pro forma
Accounts	Test Year	Test Year	Test Year	Test Year	Adjustment (A)
5920	4,342	52	4,394	3,349	(1,045)
5930	2,305	130	2,435	1,806	(629)
5970	24		24	17	(7)
5980	1		1	1	0
9010	4,749		4,749	3,174	(1,575)
9020	4,793	2,082	6,875	5,494	(1,381)
9030	594,770	210,004	804,774	613,395	(191,379)
9050	1,802	5,756	7,558	6,968	(590)
9070	8,904	18,167	27,071	24,311	(2,760)
9080	4,577	3,144	7,721	6,251	(1,470)
9100	456		456	346	(110)
9120	254		254	180	(74)
9200	1,981,079	1,138,649	3,119,728	2,495,084	(624,644)
9210	0	766	766	(1,106)	(1,872)
9220	0		0	(9)	(9)
9230	55		55	33	(22)
9250	5,260		5,260	2,679	(2,581)
9260	4,921		4,921	3,371	(1,550)
9280	75,435		75,435	48,373	(27,062)
9301	1,566		1,566	1,012	(554)
9302	13,754	1,810	15,564	11,292	(4,272)
9350	9,970	1,132	11,102	7,981	(3,121)
Grand Total	3,895,396	2,579,324	6,474,717	5,854,330	(620,385)

Additional supporting files provided electronically in WP C 2-10 AEPSC ICP Adjustment.xls

Purpose: To adjust AEPSC operating expenses for employee incentives based on a target level excluding Tur

Recap Schedules:
(A) Schedule C-2

Southwestern Electric Power Company
Pro Forma Adjustment - AEPSC Payroll
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP C 2-11

(Excludes Turk Payroll)

(1)	(2)	(3)	(4)
	Historical		(3)-(2)
FERC Acct	Test Year	Annualized	Proforma Adjustment (A)
5000	6,935,295.19	6,979,225.67	43,930.48
5010	476,797.51	490,961.64	14,164.13
5020	29,143.81	52,401.75	23,257.94
5050	1,211.02	6,791.04	5,580.02
5060	250,557.16	244,622.18	(5,934.98)
5100	696,436.30	717,630.99	21,194.69
5110	73,561.75	258,222.20	184,660.45
5120	818,710.07	562,175.61	(256,534.46)
5130	67,473.40	177,628.69	110,155.29
5140	36,794.49	70,098.66	33,304.17
5280	1,805.36	3,355.30	1,549.94
5300	32.25	59.70	27.45
5350	1,241.04	2,281.30	1,040.26
5530	3,629.76	6,744.56	3,114.80
5560	1,065,442.88	1,216,579.29	151,136.41
5570	1,872,400.43	2,095,569.67	223,169.24
5600	2,720,057.06	3,059,375.74	339,318.68
5611	32.25	59.66	27.41
5612	614,960.27	474,066.09	(140,894.18)
5615	92,879.93	74,892.60	(17,987.33)
5616	17.97	33.31	15.34
5620	439.85	812.77	372.92
5630	4,330.71	7,913.73	3,583.02
5660	405,297.91	506,212.22	100,914.31
5680	300.93	557.70	256.77
5690	315.72	581.83	266.11
5691	1,136.72	2,120.85	984.13
5692	97,575.06	96,998.92	(576.14)
5700	120,343.75	61,722.55	(58,621.20)
5710	148,020.00	167,845.79	19,825.79
5720	259.62	478.97	219.35
5730	569.42	1,055.60	486.18
5800	639,444.78	599,104.20	(40,340.58)
5820	30,649.20	56,589.75	25,940.55
5830	2,540.60	4,439.30	1,898.70
5840	8,090.06	7,871.49	(218.57)
5860	120,374.81	99,181.67	(21,193.14)
5880	538,775.60	615,039.09	76,263.49
5900	2,984.08	5,399.24	2,415.16
5920	24,605.31	44,655.42	20,050.11
5930	13,439.59	24,276.68	10,837.09
5970	137.71	249.16	111.45

Southwestern Electric Power Company **WP C 2-11**
Pro Forma Adjustment - AEPSC Payroll
Test Year Ending December 31, 2018
Docket No. 19-008-U

(Excludes Turk Payroll)

(1) FERC Acct	(2) Historical Test Year	(3) Annualized	(4) (3)-(2) Proforma Adjustment (A)
5980	6.57	12.04	5.47
9010	25,007.06	45,277.77	20,270.71
9020	44,498.93	48,889.40	4,390.47
9030	4,871,940.90	5,681,818.96	809,878.06
9050	57,794.30	17,117.90	(40,676.40)
9070	202,417.83	90,082.44	(112,335.39)
9080	51,837.06	46,071.72	(5,765.34)
9100	2,751.47	4,443.32	1,691.85
9120	449.60	773.42	323.82
9200	14,598,888.70	14,180,053.75	(418,834.95)
9210	6,145.68	0.25	(6,145.43)
9220	0.05	0.10	0.05
9230	227.88	403.69	175.81
9250	14,699.01	27,304.26	12,605.25
9260	20,590.09	38,413.06	17,822.97
9280	264,013.57	493,650.53	229,636.96
9301	8,219.25	14,872.92	6,653.67
9302	86,744.82	129,119.04	42,374.22
9350	58,131.91	87,538.71	29,406.80
	38,232,476.01	39,701,725.86	1,469,249.85

Additional supporting files provided electronically in WP C 2-11 AEPSC Payroll Adjustment.xls

Purpose: Adjustment to annualize AEPSC Payroll

Recap Schedule:
(A) Schedule C-2

Southwestern Electric Power Company **WP C 2-12**
Pro Forma Adjustment - AEPSC LTIP
Test Year Ending December 31, 2018
Docket No. 19-008-U

(Excludes Turk LTIP)

Line No.	(1) Accounts	(2) Historical Test Year	(3) Forecasted Test Year	(5) (2) + (3) Total Test Year	(6) Normalized Test Year	(7) (6) - (5) Proforma Adjustment (A)
1	5000	134,019	222,016	356,035	275,649	(80,386)
2	5010	9,774	13,833	23,607	20,105	(3,502)
3	5020	795		795	2,124	1,329
4	5050	(12)		(12)	69	81
5	5060	(28,955)	11,232	(17,723)	73,643	91,366
6	5100	9,951	33,251	43,202	23,816	(19,386)
7	5110	3,217		3,217	9,299	6,082
8	5120	13,530	32,492	46,022	27,261	(18,761)
9	5130	2,472		2,472	5,707	3,235
10	5140	1,297		1,297	2,584	1,287
11	5240	0		0	0	0
12	5280	66		66	132	66
13	5300	1		1	1	0
14	5350	28		28	70	42
15	5530	76		76	128	52
16	5560	20,960	27,998	48,958	40,965	(7,993)
17	5570	46,315	56,557	102,872	90,243	(12,629)
18	5600	47,347	28,087	75,434	87,028	11,594
19	5611	0		0	(1)	(1)
20	5612	7,016	9,056	16,072	12,602	(3,470)
21	5615	1,068	1,325	2,393	1,969	(424)
22	5616	0		0	1	1
23	5620	12		12	30	18
24	5630	158		158	293	135
25	5660	(3,964)	3,319	(645)	50,815	51,460
26	5680	6		6	14	8
27	5690	7		7	11	4
28	5691	28		28	53	25
29	5692	1,280	1,143	2,423	2,301	(122)
30	5700	778	2,189	2,967	1,490	(1,477)
31	5710	1,731	716	2,447	3,363	916
32	5720	5		5	10	5
33	5730	17		17	31	14
34	5800	8,463	1,535	9,998	17,125	7,127
35	5820	747		747	1,400	653
36	5830	71		71	154	83
37	5840	49		49	124	75
38	5860	994		994	1,899	905
39	5880	(4,887)		(4,887)	48,654	53,541
40	5900	56		56	106	50
41	5920	467	11	478	941	463
42	5930	226	28	254	447	193
43	5970	1		1	4	3
44	5980	0		0		0
45	9010	446		446	864	418
46	9020	436		436	844	408
47	9030	59,089	9,103	68,192	113,574	45,382
48	9050	179		179	344	165
49	9070	810		810	1,551	741

Southwestern Electric Power Company **WP C 2-12**
Pro Forma Adjustment - AEPSC LTIP
Test Year Ending December 31, 2018
Docket No. 19-008-U

(Excludes Turk LTIP)

	(1)	(2)	(3)	(5)	(6)	(7)
				(2) + (3)		(6) - (5)
Line		Historical	Forecasted	Total	Normalized	Proforma
No.	Accounts	Test Year	Test Year	Test Year	Test Year	Adjustment (A)
50	9080	430		430	832	402
51	9100	45		45	86	41
52	9120	(26)		(26)	(134)	(108)
53	9200	748,654	2,116,018	2,864,672	1,496,512	(1,368,160)
54	9210	0	182	182		(182)
55	9220	0		0		0
56	9230	2		2	6	4
57	9250	777		777	1,304	527
58	9260	1,165		1,165	2,325	1,160
59	9280	21,699		21,699	41,241	19,542
60	9301	167		167	313	146
61	9302	2,037		2,037	4,013	1,976
62	9350	1,092	269	1,361	2,144	783
63	Grand Total	1,112,212	2,570,361	3,682,572	2,468,475	(1,214,093)

Additional supporting files provided electronically in WP C 2-12 AEPSC LTIP Adjustment.xls

Purpose: To adjust AEPSC operating expenses for employee incentives based on a target level of 1.0.

Recap Schedules:
(A) Schedule C-2

Southwestern Electric Power Company **WP C 2-13**
Pro Forma Adjustment - Bad Debt Expense
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Description	FERC Account		Increase / (Decrease) Amount (A)
1	Reclassify the bad debt component of A/R factoring expense	9040000		3,559,843
2	from below the line Account 4265010 to utility operating expense Account 9040000	4265010	(a)	(3,559,843)
3	Adjust bad debt expense to reflect AR bad debt experience rate for 2018	9040000	(b)	($425,961)

Purpose: To reclass bad debt expense and to reflect rate for 2018

Supporting Schedules:
(a) Schedule E-17A
(b) WP C 2-13-1

Recap Schedules:
(A) Schedule C-2

Southwestern Electric Power Company **WP C 2-13-1**
Pro Forma Adjustment - Bad Debt Expense
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	(1) Description	(2) Schedule A Reference	(3) Workpaper Reference	(4) Acct Reference	(5) Exp Amt As Adjusted	(6) TY Amt Per Books (a)	Increase (Decrease) (7) Total Adjustment (A)
1	Bad Debt Expense - Retail factoring			4265	$3,133,882	3,559,842.79	($425,961)
2	Total				$3,133,882	$3,559,843	($425,961)

Line No.			Total Company	Factoring rate
	Revenues	(a)	1,418,046,241	
3	Interest Cost - Avg Dec 2018 rate		2.5746%	
4	x Debt Percent		0.95	
5	Debt Component		2.4459%	
6	Allowed ROCE	(b)	10.50%	
7	/ Tax Effect		0.73865	
8	Pretax ROCE		14.2151%	
9	x Equity Percent		0.05	
10	Equity Component		0.7108%	
11	Total Annual Weighted Cost of Capital		3.1567%	
12	/ Days in Year		365	
13	Daily Capital Cost Factor		0.000086	
14	x Average Days Outstanding		34.07	
15	Effective Carrying Cost Rate		0.2930%	
16	Estimated Carrying Cost Expense		4,154,875	
17	Effective Bad Debt Rate		0.2210%	
18	Estimated Bad Debt Expense		3,133,882	
19	Total Carrying Cost		4,154,875	0.002930
20	Total Cr Line / Banking Fees		986,780	0.000696
21	Bad Debt Expense - Using AR rate		3,133,882	0.002210
22	Total Cost		8,275,537	0.005836
23	Effective Factoring Rate		0.0058359	
24	Effective Carrying Cost - Interest + Cr Line Rate		0.0036260	

Line No.			
25	Carrying Cost		
26		3.1567%	Annual Cost of capital
27		0.6085%	Total Fees Divided by Avg. Daily balance
28		3.7652%	Total Carrying Cost

Additional supporting files provided electronically.

Purpose:
To adjust bad debt component of factoring expense based on Arkansas bad debt

Supporting Schedules:
(a) WP C 2-18
(b) Schedule D 1-3

Recap Schedules:
(A) WP C 2-13

Southwestern Electric Power Company **WP C 2-14**
Pro Forma Adjustment - Depreciation
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Depreciation and Amortization of Intangible Assets	Account	Adjustment	
1	as Calculated on Schedule F-1.3	403 & 404	268,486,982	(a)
2	Total Company Depreciation and Amortization at proposed rates		268,486,982	
3	Less: Test Year Book Depreciation Expense Schedule C-1	403 & 404	239,098,918	(b)
4	Depreciation Adjustment to Test Year		29,388,064	

Purpose: To adjust total company test year depreciation expense to reflect proposed depreciation rates applied to adjusted pro forma year end plant balances as shown on Schedule F 1.3

Supporting Schedules:
(a) Schedule F-1.3
(b) Schedule C-1

Recap Schedules:
(A) Schedule C-2

Southwestern Electric Power Company **WP C 2-14-1**
Pro Forma Adjustment - Depreciation -Turk
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Description	Acct	Increase (Decrease) (A)	
1	To eliminate depreciation expense for the Turk generation plant	403	(34,642,317)	(a)

Purpose: Turk power plant is not included in Arkansas rate base, thus asset balance and related depreciation expense are excluded in determining Arkansas retail rates

Supporting Schedules:
(a) Schedule F-1.3

Recap Schedules:
(A) Schedule C-2

Southwestern Electric Power Company
Pro Forma Adjustment - SPP Expenses
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP C 2-15

Line No.	(1) Description	(2) Acct Reference	(4) Test Year 2018	(3) Proforma 2019	(5) Total Adjustment
1	SPP Schedule 9 NITS Expense	5650	91,206,230	107,946,675	16,740,445
2	SPP Schedule 11 Base Plan Funding Expense	5650	85,016,511	78,406,199	(6,610,312)
3			176,222,741	186,352,874	10,130,133
4	**Pro Forma Adjustment increase/(decrease)**				**10,130,133**

PURPOSE
To increase SPP NITS and Base Plan Funding expenses to known and measurable levels.

Recap Schedules:
(A) Schedule C-2

Southwestern Electric Power Company
Calculation of SPP Expenses
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP 2-15-1

SOUTHWESTERN ELECTRIC POWER COMPANY
SPP Fees and Expense
For the Test Year Ended December 2018

Line No.	(1) Description	(2) Schedule A Reference	(3) Workpaper Reference	(4) Acct Reference	(5) Exp Amt As Adjusted	(6) TY Amt Per Books(a)	(7) Total Adjustment
1	SPP NITS Expense (Sch 9)			5650	107,946,675	91,206,230	16,740,445
2	SPP Base Plan Expense (Sch 11) (b)			5650	78,406,199	85,016,511	(6,610,312)
3							
4					186,352,874	##########	10,130,133
5	Amounts in table above adjusted for rounding						
6	Expense = increase / (decrease)						
7							
8	**Schedule 9 Zone 1 Rev Requirement Calc**						
9							

Line No.	SWEPCO LRS			37.6700%	(b)
11	Affiliated	Non-Affiliated	Total Share	ARR	Trans Owner
12	67,521,195		67,521,195	179,234,256	(1)
13		2,346,826	2,346,826	6,229,961	East Texas Electric Cooperative, Inc.(2)
14		0	0		Tex-La Electric Cooperative of Texas, Inc. (2)
15		369,853	369,853	981,824	Deep East Texas Electric Cooperative, Inc. (2)
16		283,353	283,353	752,198	Oklahoma Municipal Power Authority (2)
17		37,031,043	37,031,043	98,303,804	AEP West Transmission Companies (AEP Oklahoma Transmission Company, Inc and AEP Southwestern Transmission Company, Inc) (3)
18		142,545	142,545	378,405	Coffeyville Municipal Light and Power (CMPL) (2
19		251,860	251,860	668,596	Arkansas Electric Cooperative Corporation (2)
20	67,521,195	40,425,480	107,946,675	286,549,044	TOTALS Zone1

21
22 (1) Per OATT Formula Rate Filing (West Operating Companies)
23 (2) Sourced from SPP RRR file effective Nov 1, 2018
24 (3) Per OATT Formula Rate Filing (West Transmission Companies)
25 PURPOSE
26 To increase SPP NITS and Base Plan Funding expenses to known and measurable levels.

Supporting Schedules and Workpapers:
(a) E-17A
(b) WP 2-15-2

Recap Schedules:
(A) WP C 2-15

Southwestern Electric Power Company
Load Ratio Share Calculation
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP 2-15-2

American Electric Power
West Zone-SPP Network Transmission Loads (MW) and OATT Network (Sch 9) Revenue Calculation

SPP OATT NETWORK LOAD RATIO SHARE

SPP Network Customer	Peak Day Peak Hour	January 01/17/18 800	February 02/12/18 800	March 03/08/18 800	April 04/30/18 1700	May 05/30/18 1700	June 06/27/18 1700	July 07/20/18 1700	August 08/27/18 1700	September 09/19/18 1600	October 10/03/18 1700	November 11/15/18 800	December 12/0/2018 0	12 Month Average MW
PSO		3,179	2,790	2,269	2,377	3,598	3,911	4,095	3,816	3,735	3,357	2,564	2,828	3,210
SWEPCO		3,412	2,793	2,329	2,317	3,371	3,564	3,727	3,472	3,457	3,035	2,776	2,681	3,078
AECC		776	589	486	347	611	683	731	634	629	542	569	535	594
AECC -MISO		175	135	117	98	173	187	202	181	172	141	131	241	163
WFEC		47	41	34	23	36	38	42	37	36	33	36	42	37
OMPA		99	84	68	74	138	149	160	143	130	117	74	89	110
OG&E - ATOKA		5	-	5	-	5	2	2	3	-	1	8	5	3
OG&E_COALGATE		4	-	3	-	3	2	2	2	-	1	-	3	2
OG&E - TALL BEAR		12	12	14	15	15	15	15	13	13	13	14	14	14
ETEC		1,273	862	708	491	796	864	886	827	800	671	897	900	831
Greenbelt		9	7	6	8	11	14	18	15	7	7	7	8	10
Lighthouse		2	2	1	1	4	3	4	6	2	2	3	2	3
Bentonville, AR		126	103	92	86	139	158	162	144	150	123	102	108	124
Prescott, AR		9	9	9	10	9	14	15	14	13	13	5	7	11
Minden, LA		25	21	18	21	34	37	38	35	36	30	20	21	28
Hope, AR		45	43	39	39	56	57	56	56	55	52	42	36	48
Coffeyville, KS		104	98	90	61	102	106	108	104	110	109	101	98	99
SWEPCO - VALLEY		204	131	109	84	134	132	143	120	127	118	142	142	132
AECI		50	44	31	23	42	48	53	45	43	35	35	45	41
AEP-West SPP Trans Sys Peak		**9,556**	**7,764**	**6,428**	**6,075**	**9,277**	**9,984**	**10,459**	**9,667**	**9,515**	**8,400**	**7,526**	**7,805**	**8,538**

Load Ratio Share (current month)	January	February	March	April	May	June	July	August	September	October	November	December	12 Month Average
PSO	33.27%	35.94%	35.30%	39.13%	38.78%	39.17%	39.15%	39.47%	39.25%	39.96%	34.07%	36.23%	37.48%
SWEPCO	35.71%	35.97%	36.23%	38.14%	36.34%	35.70%	35.63%	35.92%	36.33%	36.13%	36.89%	34.35%	36.11%
AECC	8.12%	7.59%	7.56%	5.71%	6.59%	6.84%	6.99%	6.56%	6.61%	6.45%	7.56%	6.85%	6.95%
AECC-MISO	1.83%	1.74%	1.82%	1.61%	1.86%	1.87%	1.93%	1.87%	1.81%	1.68%	1.74%	3.09%	1.90%
WFEC	0.49%	0.53%	0.53%	0.38%	0.39%	0.38%	0.40%	0.38%	0.38%	0.39%	0.48%	0.54%	0.44%
OMPA	1.04%	1.08%	1.06%	1.22%	1.49%	1.49%	1.53%	1.48%	1.37%	1.39%	0.98%	1.14%	1.27%
OG&E - ATOKA	0.05%	0.00%	0.08%	0.00%	0.05%	0.02%	0.02%	0.03%	0.00%	0.01%	0.11%	0.06%	0.04%
OG&E_COALGATE	0.04%	0.00%	0.05%	0.00%	0.03%	0.02%	0.02%	0.02%	0.00%	0.01%	0.00%	0.04%	0.02%
OG&E - TALL BEAR	0.13%	0.15%	0.22%	0.25%	0.16%	0.15%	0.14%	0.13%	0.14%	0.15%	0.19%	0.18%	0.17%
ETEC	13.32%	11.10%	11.01%	8.08%	8.58%	8.65%	8.47%	8.55%	8.41%	7.99%	11.92%	11.53%	9.80%
Greenbelt	0.09%	0.09%	0.09%	0.13%	0.12%	0.14%	0.17%	0.16%	0.07%	0.08%	0.09%	0.10%	0.11%
Lighthouse	0.02%	0.03%	0.02%	0.02%	0.04%	0.03%	0.04%	0.06%	0.02%	0.02%	0.04%	0.03%	0.03%
Bentonville, AR	1.32%	1.33%	1.43%	1.42%	1.50%	1.58%	1.55%	1.49%	1.58%	1.46%	1.36%	1.38%	1.45%
Prescott, AR	0.09%	0.12%	0.14%	0.16%	0.10%	0.14%	0.14%	0.14%	0.14%	0.15%	0.07%	0.09%	0.12%
Minden, LA	0.26%	0.27%	0.28%	0.35%	0.37%	0.37%	0.36%	0.36%	0.38%	0.36%	0.27%	0.27%	0.33%
Hope, AR	0.47%	0.55%	0.61%	0.64%	0.60%	0.57%	0.54%	0.58%	0.58%	0.62%	0.56%	0.46%	0.57%
Coffeyville, KS	1.09%	1.26%	1.40%	1.00%	1.10%	1.06%	1.03%	1.08%	1.16%	1.30%	1.34%	1.26%	1.17%
SWEPCO - VALLEY	2.13%	1.69%	1.70%	1.38%	1.44%	1.32%	1.37%	1.24%	1.33%	1.40%	1.89%	1.82%	1.56%
AECI	0.52%	0.57%	0.48%	0.38%	0.45%	0.48%	0.51%	0.47%	0.45%	0.42%	0.47%	0.58%	0.48%
Total LRS	99.9900%	100.0100%	100.0100%	100.0000%	99.9900%	99.9800%	99.9900%	99.9900%	100.0100%	99.9700%	100.0300%	100.0000%	100.0000%

PURPOSE
To increase SPP NITS and Base Plan Funding expenses to known and

Supporting Schedules and Workpapers:

Recap Schedules
WP 2-15-1

Southwestern Electric Power Company
Base Plan Calculation Summary
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP 2-15-3

SWEPCo Portion of SPP Base Funding
Per November 2018 RRR SPP File
Estimate for base plan projects approved after June 2010

Facility Owner	SWEPCO Base Plan Regional (bpr) Charges	SWEPCO Base Plan Zonal (bpz) Charges	SWEPCO Schedule 11 Base Plan Charges
AOT	1,074,184	1,141,946	2,216,130
BEPC	1,983,919	0	1,983,919
Empire	2,126	0	2,126
GRDA	63	0	63
ITC	276,687	0	276,687
KCPL	19,405	0	19,405
KCPL-GMO	31,900	0	31,900
MKEC	463,081	0	463,081
NPPD	512,460	0	512,460
OGE	2,470,582	125,971	2,596,553
OPPD	539,676	0	539,676
PSO	20,433	291,647	312,080
SPS	1,369,667	0	1,369,667
Sunflower	28,230	0	28,230
SWEPCO	114,150	2,633,822	2,747,972
Transource	2,357,399	0	2,357,399
Westar	928,918	0	928,918
Grand Total	12,192,880	4,193,386	16,386,266

Estimate for base plan projects approved prior to June 2010

Facility Owner	SWEPCO Base Plan Regional (bpr) Charges	SWEPCO Base Plan Zonal (bpz) Charges	SWEPCO Schedule 11 Base Plan Charges
AECC	2,952	26,826	29,778
AOT	1,582,343	3,323,655	4,905,998
BEPC	54,822	0	54,822
City of Springfield	17,303	0	17,303
Empire	115,895	21,282	137,177
GRDA	166,850	79,087	245,937
ITC	5,816,303	109,199	5,925,502
KCPL	41,785	1,705	43,490
KCPL-GMO	50,140	0	50,140
LES	18,635	0	18,635
Midwest	171,703	0	171,703
MKEC	748,440	5,785	754,225
NPPD	1,360,245	26,913	1,387,158
OGE	7,488,964	2,448,877	9,937,841
OPPD	172,401	0	172,401
Prairie Wind	1,367,300	0	1,367,300
PSO	171,349	975,423	1,146,772
SPS	5,076,999	482,183	5,559,182
Sunflower	315,058	0	315,058
SWEPCO	2,902,288	16,278,092	19,180,380
Transource	550,460	0	550,460
Westar	2,050,007	340,659	2,390,666
Western Farmers	367,595	209,771	577,366
Total pre June 2010	30,609,837	24,329,456	54,939,293
Subtotal	42,802,717	28,522,842	71,325,559
Net BalPortFolio Xfer & Zonal upgrade effect (1)	8,125,163	(1,049,705)	7,075,458
Adjusted Annual Amount	50,927,880	27,473,137	78,401,017

(1) Net Bal Portfolio Transfer Effect:	ATRR	LRS	SWEPCO Share
Zonal Transfers Out	(6,124,602)	36.3%	(2,223,231)
Regional Transfers In	73,774,679	8.10%	5,975,749
Zonal to pay Upgrade Sponsors	3,234,636	36.28%	1,173,526
Regional to pay Upgrade Sponsors	12,751,581	8.10%	1,032,878
Brightline Regional to pay Upgrade Sponsors	15,170,323	7.36%	1,116,536

Additional supporting files provided electronically.

PURPOSE
To increase SPP NITS and Base Plan Funding expenses to known and measurable levels.

Supporting Schedules and Workpapers:

Recap Schedules:
WP 2-15-1

Southwestern Electric Power Company **WP C 2-16**
Pro Forma Adjustment - Economic Development
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Account	Proforma TY 2018
1	908	$ 300,000
2	Total Economic Development	**$ 300,000**
3	Note: See Company Testimony of Mr. Brice Exhibit TPB-5	

Purpose: Additonal incremental cost relating to Economic Development
i.e. Site Development & Education

Recap Schedules:
(A) Schedule C-2

Southwestern Electric Power Company
Pro Forma Adjustment - Other Taxes
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP C 2-17

Account	Description	Test Year (b)	Adjustments (a) (A)	Adjusted Pro Forma Year
4081002	FICA	10,876,194	25,860	10,902,054
4081007	State Unemployment Tax	79,692	0	79,692
4081033	Fringe Benefit Loading - FICA	(3,379,244)	0	(3,379,244)
4081003	Federal Unemployment Tax	58,748	0	58,748
4081034	Fringe Benefit Loading - FUT	(19,508)	0	(19,508)
4081035	Fringe Benefit Loading - SUT	(30,557)	0	(30,557)
	Total Payroll Taxes	7,585,325		7,611,185
408100517	Real Personal Property Taxes	(911,696)	911,696	0
408100518	Real Personal Property Taxes	64,201,415	(64,201,415)	0
408100519	Real Personal Property Taxes	0	62,177,492	62,177,492
	Ad Valorem	63,289,719	(1,112,227)	62,177,492
408102318	Local Privilege-Franchise Tax	18,005,587	0	18,005,587
408100818	State Franchise Taxes	5,165,951	0	5,165,951
408100617	State Gross Receipts Tax	2	(2)	0
408100618	State Gross Receipts Tax	6,037,591	(104)	6,037,487
	Franchise Tax	29,209,131	(106)	29,209,025
408101417	Federal Excise Taxes	518	0	518
408101418	Federal Excise Taxes	407	0	407
408101717	St Lic-Rgstrtion Tax-Fees	14,575	0	14,575
408101718	St Lic-Rgstrtion Tax-Fees	17,070	0	17,070
408101817	St Publ Serv Comm Tax-Fees	731,125	0	731,125
408101818	St Publ Serv Comm Tax-Fees	1,252,714	0	1,252,714
408101900	State Sales and Use Taxes	(311,500)	311,500	0
408101916	State Sales and Use Taxes	185,277	(185,277)	0
408101917	State Sales and Use Taxes	246	(246)	0
408101918	State Sales and Use Taxes	4,876	(4,876)	0
408102218	Municipal License Fees	80,475	0	80,475
408102917	Real-Pers Prop Tax-Cap Leases	9,469	(9,469)	0
408102918	Real-Pers Prop Tax-Cap Leases	143,834	0	143,834
	Other	2,129,086	111,632	2,240,718
	(B)	102,213,261	(1,000,701)	101,238,420

Ad Valorem Taxes Liability for 2018 Tax Year

Arkansas	15,200,000
Louisiana	25,628,710
Oklahoma	451,464
Texas	21,516,788
Total	62,796,962

Purpose: To adjust for test year and proforma taxes other than income tax including exclusion of Turk property taxes

Supporting Schedules
(a) WP C 2-17-1
(b) Schedule E-17A

Recap Schedules:
(A) Schedule C-2
(B) Schedule C-3

Southwestern Electric Power Company **WP C 2-17-1**
Pro Forma Adjustment - Other Taxes
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Description	Amount		
1	Ad valorem Tax Liability for 2018 Tax Year	62,796,961		
2	2018 Ad valorem Expensed to Acct 408	61,535,031		
3	2018 Ad -valorem expense for capitalized leases	223,474		
4	2018 Ad valorem taxes capitalized to CWIP	985,336		
5	2018 Ad valorem taxes expensed Below-the-Line	53,120		
6	Total Ad valorem taxes for 2018	62,796,961		
7	Ad valorem Tax Liability - Turk generation assets	5,069,251		
8	2018 Ad valorem Expensed to Acct 408-excl Turk	56,465,780		
9	Ad valorem Expensed to A/C 408	61,535,031		
10	A/C 101 & 106 at 01-01-2018 - Net Utility Plant	5,917,099,190		
11	Less Turk - Net Plant	1,489,127,556		
12		4,427,971,634		
13	Projected tax rate - excl. Turk	0.012752065		
	Pro forma 2019 Expense			
14	2019 Account 101 & 106 Balance - Net plant excl Turk 12-31-2019	4,875,876,314	(a)	
15	Projected tax rate - excl. Turk	0.012752065		
16	**Projected expense for 2019 pro forma year end plant -excl Turk**	**62,177,492**	(A)	
17	2019 Projected advalorem expense - Pro forma year	63,289,719	(b)	
18	**Adjustment - Increase (Decrease)**	**(1,112,227)**		**Acct 408**
19	12-31-2019 TOTAL NET PLANT	5,052,439,002	(c)	

Additional supporting files provided electronically.

Supporting Schedules
(a) WP B 2-4, WP B 2-5, WP B 2-6
(a) WP B 2-7
(b) Schedule E-17A
(c) Schedule B-1

Recap Schedule:
(A) WP C 2-17

Southwestern Electric Power Company
Pro Forma Adjustment - Revenues
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP C 2-18

Line No.	Account Number	Description	Total Test Year (a)	Remove Fuel (a)	Remove Riders (a)	Adjust Other Rev (a)	Remove Provision (a)	Remove Accrued (a)	Customer / Weather Adjustments (a)	Base Revenue Adjusted Test Year	Total Adjustments	Fuel Revenue
1		Revenue:										
2	440	Residential	668,241,696	(198,322,908)	(56,584,497)			(35,318,227)	24,945,891	402,961,955	(265,279,741)	
3	442	Commercial	480,045,546	(185,377,647)	(58,257,785)			142,053,726	16,237,183	394,701,023	(85,344,523)	
4	442	Industrial	326,906,077	(161,486,634)	(6,260,190)			(112,724,784)	735,304	47,169,773	(279,736,304)	
5	444	Other	69,726,145	(2,477,350)	(10,793,657)			(25,688,989)	5,880,096	36,646,245	(33,079,900)	
6		Total Retail	1,544,919,464							881,478,996	(663,440,468)	536,567,245
7	447	Wholesale - On System	161,165,189	(77,110,896)					482,231	84,536,524	(76,628,665)	
8	447	Wholesale - Off System	62,443,742	(62,443,742)						0	(62,443,742)	
8		Total Wholesale	223,608,931							84,536,524	(139,072,407)	75,567,344
10	449	Provision for Refund	(63,427,415)				63,427,415			0	63,427,415	
11	450,451,454,456	Miscellaneous Revenues	126,103,200			8,655,815				134,759,015	8,655,815	0
12		**Total Operating Revenues**	**1,831,204,180**	**(687,219,177)**	**(131,896,129)**	**8,655,815**	**63,427,415**	**(31,678,274)**	**48,280,705**	**1,100,774,535**	(730,429,645)	612,134,589

Purpose: To adjust revenue for removal of non-retail revenue items.

Supporting Schedules
(a) WP C 2-18-2

Recap Schedules:
(A) Schedule C-2

Southwestern Electric Power Company
Pro Forma Adjustment - Misc Revenues
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP C 2-18-1

Test Year Ending December 2018 (Actuals Jan-Jul and Forecast Aug-Dec 2018)

		Unadjusted Revenue					Adjustments					Adjusted Revenue				
Account Description	Account	Transmission	Distribution	Generation	Consolidation	Total	Transmission	Distribution	Generation	Consolidation	Total	Transmission	Distribution	Generation	Consolidation	Total
Forfeited Discounts	450	-	5,032,195	-	-	5,032,195	-	-	-	-	-	-	5,032,195	-	-	5,032,195
Misc. Service Revenues	451	-	2,250,904	-	-	2,250,904	-	-	-	-	-	-	2,250,904	-	-	2,250,904
Rent From Electric Property	454	183,182	10,008,301	287,046	(909,656)	9,568,873	(149,491)	(767,062)	-	909,656	(6,897)	33,691	9,241,239	287,046	-	9,561,976
Oth Electric Revenues	456	102,960,838	1,001,069	4,470,961	(101,636,671)	6,796,197	(101,636,671)	-	-	101,636,671	-	1,324,167	1,001,069	4,470,961	-	6,796,197
Revenues from Trans. of Electricity of Others	456.1	191,019,342	510,697	(93,656,526)	4,581,518	102,455,031	(80,735,842)	-	93,980,072	(4,581,518)	8,662,712	110,283,500	510,697	323,546	-	111,117,743
Grand Total		294,163,362	18,803,166	(88,898,519)	(97,964,809)	126,103,200	(182,522,004)	(767,062)	93,980,072	97,964,809	8,655,815	111,641,358	18,036,104	5,081,553	-	134,759,015

Southwestern Electric Power Company
Pro Forma Adjustment - Revenues
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP C 2-18-2

Line No.	Account Number	Description	Total Test Year (b)	Remove Fuel (A)	Remove Riders (A)	Adjust Other Rev (A)	Remove Rate Refund Provision (A)	Remove Accrued (A)	Customer / Weather Adjustments (A)	Adjusted Test Year
1		**Revenue:**								
2	440	Residential	668,241,696	(198,322,908)	(56,584,497)			(35,318,227)	24,945,891	402,961,955
3	442	Commercial	480,045,546	(185,377,647)	(58,257,785)			142,053,726	16,237,183	394,701,023
4	442	Industrial	326,906,077	(161,486,634)	(6,260,190)			(112,724,784)	735,304	47,169,773
5	444	Other	69,726,145	(2,477,350)	(10,793,657)			(25,688,989)	5,880,096	36,646,245
6		Total Retail	1,544,919,464							881,478,996
7	447	Wholesale - On System	161,165,189	(77,110,896)					482,231	84,536,524
8	447	Wholesale - Off System	62,443,742	(62,443,742)						0
8		Total Wholesale	223,608,931							84,536,524
10	449	Provision for Refund	(63,427,415)				63,427,415			0
11	450,451,454,456	Miscellaneous Revenues	126,103,200			8,655,815				134,759,015
12		Total Operating Revenues	**1,831,204,180**	**(687,219,177)**	**(131,896,129)**	**8,655,815**	**63,427,415**	**(31,678,274)**	**48,280,705**	**1,100,774,535**

Recap Schedules:
WP C 2-18

Southwestern Electric Power Company
Pro Forma Adjustment - Expense Removal
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP C 2-19

Line No.	Description	FERC Account	TY 2018 Amount (a)	Projected Portion of TY Amount	**Total** Pro Forma Adjustment (A)
1	Chamber of Commerce Activities				
2	Utility	9070	(1,005)	(718)	(1,723)
3	Utility	9210	(2,518)	(1,799)	(4,317)
4			**(3,523)**	**(2,517)**	**(6,040)**
5	Community Relations				
6	Utility	5060	(180)	(129)	(309)
7	Utility	5930	(35)	(25)	(60)
8	Utility	9070	(54)	(39)	(93)
9	Utility	9080	(102)	(73)	(175)
10	Utility	9210	(997)	(712)	(1,709)
11	AEPSC	9230	(5)	(4)	(9)
12	Utility	9302	(2,500)	(1,786)	(4,286)
13			**(3,873)**	**(2,768)**	**(6,641)**
14	Dues - Employee				
15	AEPSC	5000	(75)	(54)	(129)
16	AEPSC	5600	(46)	(33)	(79)
17	AEPSC	5660	(5)	(4)	(9)
18	AEPSC	9210	(225)	(161)	(386)
19	AEPSC	9302	(46)	(33)	(79)
20			**(397)**	**(285)** -	**(682)**
21	Entertainment				
22	Utility	5860	(70)	(50)	(120)
23	Utility	9010	(70)	(50)	(120)
24	Utility	9020	(80)	(57)	(137)
25	Utility	9210	(199)	(142)	(341)
26	Utility	9350	(353)	(252)	(605)
27			**(772)**	**(551)**	**(1,323)**
28	Gifts				
29	Utility	5860	(300)	(214)	(514)
30	Utility	5880	(22)	(16)	(38)
31	Utility	9010	(100)	(71)	(171)
32	Utility	9020	(100)	(71)	(171)
33	Utility	9030	(200)	(143)	(343)
34	Utility	9070	(2,505)	(1,789)	(4,294)
35	Utility	9210	(190)	(136)	(326)
36	Utility	9301	(75)	(54)	(129)
37			**(3,492)**	**(2,494)**	**(5,986)**
38	Legislative Activities				
39	Utility	9070	(323)	(231)	(554)
40	Utility	9080	(132)	(94)	(226)
41	Utility	9210	(1,792)	(1,280)	(3,072)
42	AEPSC	9210	(3,946)	(2,819)	(6,765)
43	Utility	9302	(5,700)	(4,071)	(9,771)
44	AEPSC	9302	(5,188)	(3,706)	(8,894)
45			**(17,081)**	**(12,201)**	**(29,282)**

Southwestern Electric Power Company
Pro Forma Adjustment - Expense Removal
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP C 2-19

Line No.	Description	FERC Account	TY 2018 Amount (a)	Projected Portion of TY Amount	**Total** Pro Forma Adjustment (A)
46	Other				
47	Utility	5000	(75)	(54)	(129)
48	AEPSC	5000	(190)	(136)	(326)
49	Utility	5060	(97)	(69)	(166)
50	AEPSC	5060	(87)	(62)	(149)
51	Utility	5140	(93)	(66)	(159)
52	Utility	5600	(100)	(71)	(171)
53	AEPSC	5600	(46)	(33)	(79)
54	Utility	5630	(21)	(15)	(36)
55	AEPSC	5660	(9)	(6)	(15)
56	Utility	5700	(34)	(24)	(58)
57	AEPSC	5800	(11)	(8)	(19)
58	Utility	5860	(42)	(30)	(72)
59	Utility	5880	(356)	(254)	(610)
60	Utility	9010	(168)	(120)	(288)
61	Utility	9070	(705)	(504)	(1,209)
62	AEPSC	9120	(32)	(23)	(55)
63	Utility	9210	(1,515)	(1,082)	(2,597)
64	AEPSC	9210	(294)	(210)	(504)
65			**(3,875)**	**(2,767)**	**(6,642)**
66			**(33,013)**	**(23,583)**	**(56,596)**

Line No.		
67	***Pro forma by Function:***	
68	Function	Amount
69	Production and Other Production Expenses	(1,367)
70	Transmission Expenses	(447)
71	Distribution Expenses	(1,433)
72	Customer Service and Informational Expenses	(8,274)
73	Sales Expenses	(55)
74	Customer Accounts Expenses	(1,230)
75	Administrative and General Expenses	(43,790)
76	TOTAL	(56,596)

77 Purpose:
78 To remove entertainment, gifts and other expenses considered non-recoverable.

Recap Schedules:
(A) Schedule C-2

Southwestern Electric Power Company
Pro Forma Adjustment - LA Deferred Fuel
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP C 2-20

Line Number	Account Number	Description	Increase (Decrease) Amount (A)	
1	5570004	Deferred Fuel	(4,038,022)	(a)

Purpose: To eliminate LA Deferred Fuel Expense

Supporting Schedules:
(a) Schedule E-17A

Recap Schedules:
(A) Schedule C-2

Southwestern Electric Power Company **WP C 2-21**
Pro Forma Adjustment - Turk Expense Removal
Test Year Ending December 31, 2018
Docket No. 19-008-U

	(1)	(2)	(3)	
Line Number	**Account**	**Account Description**	**2018 Total (a)**	
1	4081	Payroll Taxes	652,621	
2	500	Oper Supervision & Engineering	793,268	
3	505	Electric Expenses	2,489,268	
4	506	Misc Steam Power Expenses	976,525	
5	510	Maint Supv & Engineering	785,860	
6	511	Maintenance of Structures	1,435,609	
7	512	Maintenance of Boiler Plant	6,898,165	
8	513	Maintenance of Electric Plant	802,413	
9	514	Maintenance of Misc Steam Plt	891,020	
10	557	Other Expenses	(15,264)	
11	566	Misc Transmission Expenses	(105)	
12	920	Administrative & Gen Salaries	31,588	
13	921	Off Supl & Exp - Nonassociated	65	
14	924	Property Insurance	481,927	
15	923	Outside Svcs Empl - Nonassoc	8,300	
16	925	Frg Ben Loading - Workers Comp	294,078	
17	926	Savings Plan Contributions	680,719	
18		Total:	17,206,057	
19		Adj excluding payroll taxes	16,553,436	(A)

Note: Property taxes for Turk are eliminated in the property tax adjustment
See WP C-2-17

Purpose: To exclude Turk expenses that are not included in the cost of service

Supporting Schedules:
(a) WP C 2-21-1

Recap Schedules:
(A) Schedule C-2

Southwestern Electric Power Company **WP C 2-21-1**
Pro Forma Adjustment - Turk Expense Removal
Test Year Ending December 31, 2018
Docket No. 19-008-U

	(1)	(2) (3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Line No.	Account	Account Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2018 Total
1	4081xxx	Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	- [1]
2	4081xxx	Payroll Tax	54,385	54,385	54,385	54,385	54,385	54,385	54,385	54,385	54,385	54,385	54,385	54,385	652,621 [2]
3	5000000	Oper Supervision & Engineering	111,180	87,624	149,493	97,852	127,681	94,195	110,942						778,967 [3]
4	5000001	Oper Super & Eng-RATA-Affil	2,666	33	6,374	1,047	3,978	203							14,301 [3]
5	5050000	Electric Expenses	57,833	62,476	79,008	60,966	28,027	33,258	70,062	416,202	420,153	420,194	420,328	420,762	2,489,268 [3]
6	5060000	Misc Steam Power Expenses	78,014	110,982	152,729	121,088	100,474	81,961	109,065	56,166	55,063	16,563	27,962	66,459	976,525 [3]
7	5100000	Maint Supv & Engineering	143,596	142,347	137,927	103,814	143,875	106,642	102,277	(197,428)	112	61,682	40,904	112	785,860 [3]
8	5110000	Maintenance of Structures	121,140	88,670	141,679	159,814	305,851	310,964	93,607	51,212	51,208	37,154	37,153	37,157	1,435,609 [3]
9	5120000	Maintenance of Boiler Plant	588,836	424,784	743,364	15,787	1,108,131	(152,542)	369,832	623,248	900,519	959,318	682,549	633,457	6,897,282 [3]
10	5120025	Maint of Blr Plt Environmental	75	88			633		88						883 [3]
11	5130000	Maintenance of Electric Plant	38,473	62,531	91,277	64,866	310,690	123,230	58,256	3,300	21,614	21,620	3,278	3,279	802,413 [3]
12	5140000	Maintenance of Misc Steam Plt	104,068	115,867	133,712	97,194	98,214	170,869	147,003	4,834	4,814	4,820	4,811	4,813	891,020 [3]
13	5570000	Other Expenses						(15,264)							(15,264) [3]
14	5660000	Misc Transmission Expenses			(105)										(105) [3]
15	9200000	Administrative & Gen Salaries	1,444	3,016	2,484	4,238	8,445	6,093	5,868						31,588 [3]
16	9210001	Off Supl & Exp - Nonassociated	9	11	6	18	6	6	9						65 [3]
17	9240000	Property Insurance	40,161	40,161	40,161	40,161	40,161	40,161	40,161	40,161	40,161	40,161	40,161	40,161	481,927 [4]
18	9230001	Outside Svcs Empl - Nonassoc	280				7,720	150	150						8,300 [3]
19	9250xxx	Frg Ben Loading - Workers Comp	24,507	24,507	24,507	24,507	24,507	24,507	24,507	24,507	24,507	24,507	24,507	24,507	294,078 [5]
20	9260xxx	Savings Plan Contributions	56,727	56,727	56,727	56,727	56,727	56,727	56,727	56,727	56,727	56,727	56,727	56,727	680,719 [6]
21		Total:	1,423,395	1,274,208	1,813,728	902,464	2,419,504	935,544	1,242,937	1,133,314	1,629,263	1,697,131	1,392,765	1,341,819	17,206,057

22 Note that Turk fuel expense in accounts 151 and 152 are adjusted in a separate adjustment.

Southwestern Electric Power Company **WP C 2-21-1**
Pro Forma Adjustment - Turk Expense Removal
Test Year Ending December 31, 2018
Docket No. 19-008-U

23 [1] Property Taxes included in adjustment 2-17
24
25
26

Line	[2] Turk payroll taxes based on Departments 12810 (Plant) and 13141 (Stores)	YTD	Used Oct. 2018 actual as forecast		Total
28		Oct-18	Nov-18	Dec-18	2018
29	OASDI	549,745.07	49,662.23	49,662.23	649,070
30	Medicare	130,177.44	11,839.14	11,839.14	153,856
31	Unemployment-Federal	4,788.00	-	-	4,788
32	Unemployment-State	6,840.00	-	-	6,840
33	Total				814,554
34	Portion of SWEPCo Generation Labor Expensed				80.12%
35	Net Turk Payroll Taxes Expensed				652,621

Turk Portion of Payroll Calculations (Payroll calculations are based on the same method as calculating labor the FERC Form 1, pages 354 and 355)

For all SWEPCo generation actual payroll through October 2018

Charged Expense Accounts (5xx or 9xx)	38,902,181
Total SWEPCo Generation Labor	48,554,719
	80.12%

36 [3] From Budget, 7 months of actual plus 5 months of forecast equa **15,096,712** Additional supporting files provided electronically. See Turk 2018 OM CC and ForecastCombined 7+5.xls.

Line	[4] Schedule E-17A(b)	1/31/2018	2/28/2018	3/31/2018	4/30/2018	5/31/2018	6/30/2018	7/31/2018	8/31/2018	9/30/2018	10/31/2018	11/30/2018	12/31/2018	Total
38	924 Property Insurance	170,389	173,509	173,506	162,882	536,112	199,961	185,866	200,558	200,558	200,557	200,557	200,557	2,605,012
39	Turk portion of Gross Plant													18.50%
40	Turk Property Insurance (Total SWEPCo property insurance times Turk portion of gross plant)													481,927

Line	Turk Portion of Gross Plant Calculation														13-Month
42	Schedule E-17 Part II A(b	12/31/2017	1/31/2018	2/28/2018	3/31/2018	4/30/2018	5/31/2018	6/30/2018	7/31/2018	8/31/2018	9/30/2018	10/31/2018	11/30/2018	12/31/2018	Average
43	Turk Plant	1,658,620,985	1,658,645,031	1,658,671,481	1,658,680,059	1,658,401,386	1,658,824,862	1,660,740,859	1,661,511,973	1,659,774,237	1,664,024,050	1,669,043,161	1,674,106,805	1,675,882,772	1,662,840,589
44	Total Plant	8,825,159,249	8,843,910,679	8,853,493,285	8,891,103,414	8,898,667,160	8,935,354,538	9,004,848,698	9,029,529,860	9,033,542,957	9,063,243,223	9,112,094,756	9,152,788,763	9,198,366,842	8,987,854,110
45	Turk portion of Gross Plai (Turk Plant divided by Total SWEPCo Plant)														18.50%

Line	[5] Schedule E-17A (b)	1/31/2018	2/28/2018	3/31/2018	4/30/2018	5/31/2018	6/30/2018	7/31/2018	8/31/2018	9/30/2018	10/31/2018	11/30/2018	12/31/2018	Total
47	925 Injuries and Damages	282,355	323,390	245,548	368,471	882,181	258,763	428,030	358,516	358,502	375,673	358,734	361,996	4,602,159
48	Turk portion of SWEPCo labor													6.39%
49	Turk Injuries and Damages (Total SWEPCo infuries and damages times Turk portion of labor cost)													294,078

Line	[6] Schedule E-17A (b)	1/31/2018	2/28/2018	3/31/2018	4/30/2018	5/31/2018	6/30/2018	7/31/2018	8/31/2018	9/30/2018	10/31/2018	11/30/2018	12/31/2018	Total
51	926 Pensions and Benefits	447,971	872,146	1,569,392	929,873	797,499	915,267	759,773	854,210	877,648	878,280	876,962	873,862	10,652,883
52	Turk portion of SWEPCo labor													6.39%
53	Turk Pensions and Benefits (Total SWEPCo property insurance times Turk portion of gross plant)													680,719

54 Turk Portion of Payroll Calculations (Payroll calculations are based on the same method as calculating labor the FERC Form 1, pages 354 and 355)

Line		
54	Total Turk Labor (c)	7,885,273
55	Total SWEPCO Labor (c)	123,399,067
56	Turk portion of SWEPCO labor (c)	6.39%

Supporting Schedules
(a) WP C 2-21-2
(b) A E-17 Part II A

Recap Schedules:
WP C 2-21

Southwestern Electric Power Company
SWEPCO Calculation of Payroll O&M Ratio
Test Year Ending December 31, 2018
Docket No. 19-008-U
Actual payroll data through October 31, 2018

WP C-21-2

SWEPCo Payroll O&M Ratio

SWEPCO O&M Ratio 80.1203%

Purpose: Calculate an O&M ratio for alloction of capital/O&M splits.

Total SWEPCO Generation Payroll

Account	Amount
1070000	-
1070001	1,838,803
1080000	-
1080005	467,951
1510017	348,159
1520000	4,219,383
1630032	25,282
1630033	211
1630045	69
1630053	70,297
1630054	347
1630055	207,496
1630056	104,158
1630057	63,104
1630058	88
1630059	196,749
1630060	72,506
1630061	236,690
1630157	6,295
1630159	200,278
1830000	(19,931)
1840019	164
1840029	28
1840030	3
1840033	1,232,973
1840034	375,827
1840035	-
1880000	-
2420649	-
4010001	6,540
4264000	53,714
4265002	-
4560012	(54,646)
5000000	3,739,070
5010000	8,883
5020000	8,557,925
5020001	29,566
5020008	7,561
5020013	1,276
5020014	5,901
5020025	72,205
5050000	6,913,953
5060000	3,063,626
5100000	3,667,861
5110000	1,017,447
5120000	6,968,950
5130000	2,012,084
5140000	1,611,725
5240000	76
5480000	168,887
5530001	277,825
5570000	15,168
9040007	1,100
9200000	703,365
9210001	6,030
9220000	(55)
9260006	139
9260014	40,137
9260036	9,681
9280002	1,795
Grand Total	48,554,719

Total SWEPCO Generation O&M Payroll

Account	Amount
5000000	3,739,070
5010000	8,883
5020000	8,557,925
5020001	29,566
5020008	7,561
5020013	1,276
5020014	5,901
5020025	72,205
5050000	6,913,953
5060000	3,063,626
5100000	3,667,861
5110000	1,017,447
5120000	6,968,950
5130000	2,012,084
5140000	1,611,725
5240000	76
5480000	168,887
5530001	277,825
5570000	15,168
9040007	1,100
9200000	703,365
9210001	6,030
9220000	(55)
9260006	139
9260014	40,137
9260036	9,681
9280002	1,795
Grand Total	########

Southwestern Electric Power Company **WP C 2-22**
Pro Forma Adjustment - Grid Assurance
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line Number	Account Number	Description	Increase (Decrease) Amount (A)
1	5650000	PJM NITS Expense - Affiliated	215,230
2			
3	AEP Grid Assurance Estimated Annual Fee		1,774,000
4	SWEPCO's Estimated Allocation based on		
5	Transmission Asssets		215,230
6	Note: See testimony of Company witness Smoak.		

Purpose: To include estimated costs related to Grid Assurance fee.

Recap Schedules:
(A) Schedule C-2

Southwestern Electric Power Company **WP C 2-23**
Pro Forma Adjustment - EEI
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Description	Account	Historical 7/31/2018	Proforma	Amount
1	Adjust EEI Charges (1)	9302003	1,617.97	(48.54)	$ 1,569.43
2	Pro Forma Adjustment #23	9302003			**$ (48.54)** (A)

(1) - Source: Annual dues statement from EEI.
PURPOSE:
To adjust EEI Charges to a 3% reduction based on estimated lobbying component of EEI Charge

Recap Schedules:
(A) Schedule C-2

Southwestern Electric Power Company **WP C 2-24**
Pro Forma Adjustment - Advertising
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Description	FERC Account			Amount
1	Test year expense Account 909		(a)	$	14,453
2	Test year expense Account 930.1		(a)	$	258,800
3	Total Expense			$	273,253
4	Unrecoverable Advertising - Account 909			$	-
5	Unrecoverable Advertising - Account 930.1		(a)	$	(22,410)
6	**Pro Forma adjustment**	913, 909, 930.1		**$**	**(22,410)**
	Pro Forma Adjustment by FERC account				
7	Account 909			$	-
8	Account 913				(22,410)
9	Total				(22,410) (A)

Purpose: To eliminate unrecoverable advertising expesnes from cost of service.

Supporting Schedules
(a) Schedule C-7

Recap Schedules:
(A) Schedule C-2

Southwestern Electric Power Company **WP C 2-25**
Pro Forma Adjustment - Customer Account Processing Expense
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Account	Estimated Number of Arkansas Transactions Monthly Average	Monthly Cost at $1.25	Proforma Test Year Estimated Cost	
1	903	$ 18,528.57	$ 23,160.71	$ 277,929	
				$ 277,929	(A)

Note: See also the testimony of Mr. Brice.

Purpose: Adjust for additional cost relating to credit card fees from Bill Matrix

Recap Schedules:
(A) Schedule C-2

Southwestern Electric Power Company **WP C 2-26**
Pro Forma Adjustment - Income Tax
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Account	Description	Test Year (a)	Adjustments (A)	Pro Forma Year Income Tax Expense	
1	4091	FIT -current	22,913,183	(2,093,009)	20,820,174	(b)
2	4091002	SIT - current	4,518,352	(1,384,442)	3,133,910	(b)
3		Current	27,431,535	(3,477,451)	23,954,084	
4	4101	Prov Def Inc Tax, Util Oper In	777,092,760	(790,208,555)	(13,115,795)	(c)
5	4111	Prov Def I/T-Cr Util Oper Inc-Fed	(782,342,934)	782,342,934		
6	4111	Prov Def I/T-Cr Util Oper Inc-State	(1,395,116)	1,395,116	0	
7		Net Prov Def Inc Tax	(6,645,290)	(6,470,505)	(13,115,795)	
8	4114	ITC Adj, Utility Operations	(1,244,396)	857,639	(386,757)	(d)
9		Total	19,541,849	(9,090,317)	10,451,532	

10

Purpose: To adjust Test year Income tax expense to reflect the pro forma year operating results.

Supporting Schedules
(a) Schedule E-17A
(b) Schedule C-11
(c) Schedule C-12
(d) Schedule C-9

Recap Schedule:
(A) Schedule C-2

Southwestern Electric Power Company **SCHEDULE C-3**
Derivation of Test Year Statement of Utility Operating Income
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the derivation of projected test year statement of utility operating income from financial records of the Company by account, subtotaled by function. This schedule is not necessary if an entirely historical test year is being used.

(1) Account Number	(2) Account Description	(3.00) Actual Amount per Trial Balance for Historical Portion of Test Year (a)	(4) Projected Activity for Projected Portion of Test Year (a)	(5) Total Test Year (Col. 3 + Col. 4) (A)
	Operating Revenue: by rate class			
440	Residential	398,591,335.17	269,650,361.00	668,241,696.17
442	Commercial & Industrial	505,392,278.07	362,528,000.00	867,920,278.07
444	Street Light	5,240,442.47	3,517,048.00	8,757,490.47
445	Public Authorities	0.00	0.00	0.00
449.1	Provision for Refund	(52,857,113.30)	(10,570,302.00)	(63,427,415.30)
	Total System	**856,366,942.41**	**625,125,107.00**	**1,481,492,049.41**
447	Munis & COOP's	45,877,201.88	16,566,540.00	62,443,741.88
447	Sales for Resale	105,238,985.56	55,926,203.00	161,165,188.56
	Total Sales Revenue	**1,007,483,129.85**	**697,617,850.00**	**1,705,100,979.85**
450, 451, 454, 456	Other Operating Revenue	77,152,614.62	48,950,585.00	126,103,199.62
	Total Operating Revenues	**1,084,635,744.47**	**746,568,435.00**	**1,831,204,179.47**
	Operating Expenses:			
	Operating & Maintenance Expenses:			
	Power Production:			
	Operation:			
	Fuel:			
501, 547	Coal, Gas, Other	302,422,580.35	208,569,986.00	510,992,566.35
	Total Fuel	**302,422,580.35**	**208,569,986.00**	**510,992,566.35**
555	Purchased Power	122,318,643.52	57,857,446.00	180,176,089.52
	Other Production:			
	Operation Expenses:			
500, 546	Supervision & Engineering	11,236,544.07	8,165,248.00	19,401,792.07
502	Steam Expenses	13,378,010.41	6,413,894.00	19,791,904.41
505, 548	Electric Expenses	6,326,896.83	3,005,657.00	9,332,553.83
;, 507, 509, 549, 550, 556, !	Miscellaneous Expenses	15,914,497.37	15,182,308.00	31,096,805.37
	Total Operation Expenses	**46,855,948.68**	**32,767,107.00**	**79,623,055.68**
	Maintenance Expenses:			
510, 551	Supervision & Engineering	3,667,569.50	2,427,183.00	6,094,752.50
511, 552	Structures	3,662,375.07	431,583.00	4,093,958.07
512	Boiler Plant	22,344,674.50	30,866,313.00	53,210,987.50
513, 553	Electric Plant	6,225,710.27	696,979.00	6,922,689.27
514, 554	Miscellaneous	3,658,305.99	1,337,727.00	4,996,032.99
	Total Maintenance Expenses	**39,558,635.33**	**35,759,785.00**	**75,318,420.33**
	Total Other Production Expense	86,414,584.01	68,526,892.00	154,941,476.01
	Total Production Expenses	**511,155,807.88**	**334,954,324.00**	**846,110,131.88**

Southwestern Electric Power Company **SCHEDULE C-3**
Derivation of Test Year Statement of Utility Operating Income
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the derivation of projected test year statement of utility operating income from financial records of the Company by account, subtotaled by function. This schedule is not necessary if an entirely historical test year is being used.

(1) Account Number	(2) Account Description	(3.00) Actual Amount per Trial Balance for Historical Portion of Test Year (a)	(4) Projected Activity for Projected Portion of Test Year (a)	(5) Total Test Year (Col. 3 + Col. 4) (A)
	Transmission:			
	Operation Expenses:			
560	Supervision & Engineering	5,736,384.44	1,504,304.00	7,240,688.44
561 - 561.8	Load Dispatching	7,813,897.48	6,733,419.00	14,547,316.48
562	Station Yards	538,706.99	1,637.00	540,343.99
563	Overhead Lines	411,800.87	10,094.00	421,894.87
564 - 567	Miscellaneous	58,448,937.44	39,635,103.00	98,084,040.44
	Total Operation Expenses	**72,949,727.22**	**47,884,557.00**	**120,834,284.22**
	Maintenance Expenses:			
568	Supervision & Engineering	41,077.34	0.00	41,077.34
569 - 569.4	Structures	436,301.49	140,692.00	576,993.49
570	Station Equipment	1,170,243.68	2,424,014.00	3,594,257.68
571	Overhead Lines	5,657,735.36	4,671,065.00	10,328,800.36
572, 573	Other	38,783.82	0.00	38,783.82
	Total Maintenance Expenses	**7,344,141.69**	**7,235,771.00**	**14,579,912.69**
	Total Transmission Expenses	**80,293,868.91**	**55,120,328.00**	**135,414,196.91**
575.7	Total Market Op Expense	933,355.66	581,580.00	1,514,935.66
	Distribution:			
	Operation Expenses:			
580	Supervision & Engineering	1,345,876.36	1,108,569.00	2,454,445.36
581	Load Dispatching	31,266.71	260.00	31,526.71
582	Station Yards	403,171.65	0.00	403,171.65
583	Overhead Line Expenses	1,153,294.66	1,992,751.00	3,146,045.66
584	Underground Line Expenses	971,743.94	1,170,222.00	2,141,965.94
585	Street Lighting	82,732.76	119,717.00	202,449.76
586	Meter Expenses	2,175,847.47	1,342,968.00	3,518,815.47
587	Customer Installations	331,299.25	390,720.00	722,019.25
588, 589	Miscellaneous	11,279,056.86	8,706,948.00	19,986,004.86
	Total Operation Expenses	**17,774,289.66**	**14,832,155.00**	**32,606,444.66**
	Maintenance Expenses:			
590	Supervision & Engineering	180,854.99	188,240.00	369,094.99
591	Structures	22,518.99	0.00	22,518.99
592	Station Equipment	638,030.37	26,070.00	664,100.37
593	Overhead Lines	26,130,121.60	21,666,824.00	47,796,945.60
594	Underground Lines	486,175.16	535,039.00	1,021,214.16
595	Line Transformers	138,851.56	1,468.00	140,319.56
596	Street Lighting	274,441.14	118,492.00	392,933.14
597	Meters	286,132.96	192,022.00	478,154.96
598	Miscellaneous	169,101.03	76,897.00	245,998.03
	Total Maintenance Expenses	**28,326,227.80**	**22,805,052.00**	**51,131,279.80**
	Total Distribution Expenses	**46,100,517.46**	**37,637,207.00**	**83,737,724.46**
	Customer Service & Informational:			
907	Supervision	4,287,022.45	3,160,092.00	7,447,114.45
908	Customer Assistance	8,431,134.86	5,430,491.00	13,861,625.86
909	Informational and Instructional Expe	192.99	14,260.00	14,452.99
910	Miscellaneous	6,921.60	0.00	6,921.60
	Total Customer Service & Informa	**12,725,271.90**	**8,604,843.00**	**21,330,114.90**
	Sales Expenses:			
911	Supervision	321.35	0.00	321.35
912	Demonstrating & Selling	103,496.82	62,736.00	166,232.82
913	Advertising	0.00	0.00	0.00
916	Miscellaneous	0.00	0.00	0.00
	Total Sales Expenses	**103,818.17**	**62,736.00**	**166,554.17**

Southwestern Electric Power Company **SCHEDULE C-3**
Derivation of Test Year Statement of Utility Operating Income
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the derivation of projected test year statement of utility operating income from financial records of the Company by account, subtotaled by function. This schedule is not necessary if an entirely historical test year is being used.

(1) Account Number	(2) Account Description	(3.00) Actual Amount per Trial Balance for Historical Portion of Test Year (a)	(4) Projected Activity for Projected Portion of Test Year (a)	(5) Total Test Year (Col. 3 + Col. 4) (A)
	Customer Accounts Expenses:			
901	Supervision	415,482.18	251,758.00	667,240.18
902	Meter Reading	1,270,898.58	890,279.00	2,161,177.58
903	Customer Records & Collections	9,917,380.71	5,947,324.00	15,864,704.71
904	Uncollectible Accounts	(525,204.90)	0.00	(525,204.90)
905	Miscellaneous	55,522.02	91,284.00	146,806.02
	Total Customer Accounts Expens	**11,134,078.59**	**7,180,645.00**	**18,314,723.59**
	Administrative & General Expenses:			
	Operations:			
920	Salaries	16,894,919.20	15,544,875.00	32,439,794.20
921	Office Supplies & Expenses	1,732,594.50	1,213,049.00	2,945,643.50
922	Administrative Expenses Transferre	(2,459,825.55)	(1,211,873.00)	(3,671,698.55)
923	Outside Services	2,845,814.46	14,806,070.00	17,651,884.46
924	Property Insurance	1,602,224.40	1,002,788.00	2,605,012.40
925	Liability Insurance	2,788,738.26	1,813,421.00	4,602,159.26
926	Pensions & Benefits	6,291,921.10	4,360,962.00	10,652,883.10
927	Franchise Requirements	0.00	0.00	0.00
928	Regulatory Commission Expenses	2,821,313.84	136,820.00	2,958,133.84
929	Duplicate Charges	0.00	0.00	0.00
930.1	Corporate Communications	172,003.38	86,796.00	258,799.38
930.2	Miscellaneous	895,189.83	386,762.00	1,281,951.83
931	Rents	517,084.58	379,420.00	896,504.58
	Total Operations	**34,101,978.00**	**38,519,090.00**	**72,621,068.00**
935	Maintenance of General Plant	4,136,964.85	2,208,597.00	6,345,561.85
	Total Administrative & General Expenses	38,238,942.85	40,727,687.00	78,966,629.85
	Total Operating & Maintenance Expense	**700,685,661.42**	**484,869,350.00**	**1,185,555,011.42**
403, 403.1	Depreciation Expense	124,850,633.98	96,609,383.00	221,460,016.98
404	Amortization Expense	9,702,457.11	7,936,442.00	17,638,899.11
407	Regulatory Debits	1,062,351.49	1,538,956.00	2,601,307.49
408.1	Taxes Other than Income	59,377,827.19	42,835,433.00	102,213,260.19
409.1	Federal and State Income Taxes	22,681,119.39	4,750,416.00	27,431,535.39
410.1	Deferred Federal Income Taxes	769,908,856.27	7,183,904.00	777,092,760.27
411.1	Deferred Federal Income Taxes - Cı	(772,928,426.89)	(10,809,623.00)	(783,738,049.89)
411.4	Investment Tax Credit - net	(829,626.00)	(414,770.00)	(1,244,396.00)
411.6, 411.8	Gain from Disposition of Allowances	619,127.29	0.00	619,127.29
411.10	Accretion	1,547,120.25	1,011,073.00	2,558,193.25
	Total Operating Expenses	916,677,101.50	635,510,564.00	1,552,187,665.50
	Net Utility Operating Income	**167,958,642.97**	**111,057,871.00**	**279,016,513.97**

Supporting Schedules:
(a) Schedule E-17

Recap Schedules
(A) Schedule C-1

Southwestern Electric Power Company **SCHEDULE C-4**
Calculation of Percentage of Uncollectible Accounts and Forfeited Discounts
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the gross jurisdictional operating revenues and the amount of uncollectible accounts written off and forfeited discounts, if collected, by rate class for the test year and the last (4) non-overlapping fiscal years. Amounts in Column 4 should be net write-offs (gross write-offs minus recoveries), not provision for expense in income statement. If test year is partially projected, use five (5) preceding non-overlapping fiscal years.

(1) Line No.	(2) Description	(3) Arkansas Jurisdictional Operational Revenues	(4) Arkansas Jurisdictional Uncollectibles - Net of Recoveries	(5) Uncollectible Ratio (Col. 4/ Col. (3) (A)	(6) Arkansas Jurisdictional Forfeited Discounts	(7) Forfeited Discounts Ratio (Col.6/ Col.3) (A)
1	Five Year Total by Rate Class	**$ 1,437,088,485**	**$ 4,606,514**	**0.320545%**	**$ 6,694,031**	**0.465805%**
2	Commercial	492,158,486	226,309	0.045983%		
3	Industrial	430,638,523	36,725	0.008528%		
4	Other	9,145,852	-	0.000000%		
5	Residential	505,145,624	4,343,480	0.859847%		
6	2017	**288,452,599**	**690,508**	**0.239384%**	**$ 1,321,246**	**0.458046%**
7	Commercial	100,510,199	20,737	0.020632%		
8	Industrial	83,073,231	47	0.000057%		
9	Other	1,860,564	-	0.000000%		
10	Residential	103,008,605	669,724	0.650163%		
11	2016	**284,438,613**	**691,592**	**0.243143%**	**$ 1,288,451**	**0.452980%**
12	Commercial	97,816,524	38,792	0.039658%		
13	Industrial	82,713,492	3,147	0.003805%		
14	Other	1,811,854	-	0.000000%		
15	Residential	102,096,743	649,653	0.636311%		
16	2015	**272,789,352**	**931,181**	**0.341355%**	**$ 1,350,339**	**0.495012%**
17	Commercial	94,691,742	33,674	0.035562%		
18	Industrial	79,633,293	26,168	0.032861%		
19	Other	1,786,607	-	0.000000%		
20	Residential	96,677,710	871,339	0.901282%		
21	2014	**293,234,103**	**1,255,099**	**0.428019%**	**$ 1,379,364**	**0.470397%**
22	Commercial	99,119,829	90,708	0.091513%		
23	Industrial	91,544,363	7,379	0.008061%		
24	Other	1,836,360	-	0.000000%		
25	Residential	100,733,551	1,157,012	1.148587%		
26	2013	**298,173,818**	**1,038,134**	**0.348164%**	**$ 1,354,631**	**0.454309%**
27	Commercial	100,020,192	42,398	0.042389%		
28	Industrial	93,674,144	(16)	-0.000017%		
29	Other	1,850,467	-	0.000000%		
30	Residential	102,629,015	995,752	0.970244%		
31	Total	**$ 1,437,088,485**	**$ 4,606,514**	**0.320545%**		

Supporting Schedules

Recap Schedules
(A) Schedule C-5

Southwestern Electric Power Company
Calculation of Revenue Conversion Factor
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE C-5

Explanation: Schedule showing incremental taxes and uncollectible accounts on incremental operating revenues and the development of a revenue conversion factor by rate class.

(1) Line No.	(2) Description	(3) Total	(4) Commercial	(5) Industrial	(6) Public Authority	(7) Residential
1	Arkansas Corporate Tax Rate	6.50%	6.50%	6.50%	6.50%	6.50%
2	Federal Corporate Tax Rate	21%	21%	21%	21%	21%
3	Composite Tax Rate (1)	0.261350	0.261350	0.261350	0.261350	0.261350
4	Uncollectible Accounts Ratio (a)	0.003205	0.000460	0.000090	0.000000	0.008613
5	Forfeited Discounts Ratio (a)					
6	Revenue Conversion Factor (2) (A) (B)	1.358174	1.354444	1.353943	1.353821	1.365583

(1) Composite Tax Rate = L1 + (1-L1)(L2)
(2) Revenue Conversion Factor* = 1 / ((1-L3)*(1-L4+L5))

* Forfeited Discounts Ratio is not required in Revenue Conversion Factor

Supporting Schedules and Workpapers:
(a) Schedule C-4

Recap Schedules
(A) Schedule A-1
(B) Schedule G-1

Southwestern Electric Power Company
Other Expenditures
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE C-6

Explanation: Disclosure of all expenditures in support of or membership in social, recreational, fraternal, religious clubs or organizations, Chambers of Commerce, and civic associations, lobbying or charitable contributions which are included in the test year utility operating expense. Include these expenditures for the utility, as well as the service company or other affiliate, if included in test year utility operating expense.

(1) Line No.	(2) Account Number	(3) Expenditure Description	(4) Actual Test Year Booked Amount (A)	(5) Projected Portion of Test Year Amount	(6) Total Amount
1		**Community Relations**	**$ 2,715**	**$ 1,939**	**$ 4,654**
2					
3	5060	LONGVIEW LIONS CLUB	180	129	309
4	5930	ARBOR DAY FOUNDATION	35	25	60
5	9302	ARKANSAS ENVIRONMENTAL FEDERATION	1,800	1,286	3,086
6		BOSSIER PARISH COMMUNITY COLLEGE CAVALIER ATHLETI	100	71	171
7		FOUR STATES FAIR ASSOCIATION	100	71	171
8		MARTIN LUTHER KING COMMUNITY DEVELOPMENT	500	357	857
9					
10		**Dues- Chamber of Commerce**	**$ 29,290**	**$ 20,919**	**$ 50,209**
11	9210	DESOTO PARISH CHAMBER OF COMMERCE	100	71	171
12	9302	ARKANSAS STATE CHAMBER OF COMMERCE	5,000	3,571	8,571
13		BENTONVILLE/BELLA VISTA CHAMBER	500	357	857
14		BOSSIER CHAMBER OF COMMERCE	1,050	750	1,800
15		DAINGERFIELD CHAMBER OF COMMERCE	300	214	514
16		DEQUEEN/SEVIER COUNTY CHAMBER OF COMMERCE	400	286	686
17		FAYETTEVILLE CHAMBER OF COMMERCE	3,766	2,690	6,456
18		GILMER AREA CHAMBER OF COMMERCE	150	107	257
19		GLADEWATER CHAMBER OF COMMERCE	150	107	257
20		GRAND SALINE CHAMBER OF COMMERCE	125	89	214
21		GREATER EUREKA SPRINGS CHAMBER OF COMMERCE	750	536	1,286
22		GREATER MINDEN CHAMBER	600	429	1,029
23		GREATER SHREVEPORT CHAMBER OF	2,900	2,071	4,971
24		GREENWOOD CHAMBER OF COMMERCE	800	571	1,371
25		HAWKINS CHAMBER OF COMMERCE	50	36	86
26		HENDERSON AREA CHAMBER OF COMMERCE	500	357	857
27		HOPE-HEMPSTEAD COUNTY CHAMBER	650	464	1,114
28		KILGORE CHAMBER OF COMMERCE	530	379	909
29		LITTLE RIVER CHAMBER OF COMMERCE	500	357	857
30		LITTLE ROCK REGIONAL CHAMBER OF COMMERCE	350	250	600
31		MARSHALL CHAMBER OF COMMERCE	650	464	1,114
32		MENA/POLK COUNTY CHAMBER OF	750	536	1,286
33		MINEOLA CHAMBER OF COMMERCE	250	179	429
34		MOUNT PLEASANT / TITUS COUNTY CHAMBER OF COMMER(	308	220	528
35		NASHVILLE CHAMBER OF COMMERCE	450	321	771
36		NATCHITOCHES CHAMBER OF COMMERCE	1,025	732	1,757
37		NEW BOSTON CHAMBER OF COMMERCE	130	93	223
38		PANOLA COUNTY CHAMBER OF COMMERCE	175	125	300
39		PRESCOTT-NEVADA COUNTY CHAMBER	500	357	857
40		ROGERS-LOWELL AREA CHAMBER OF COMMERCE	1,801	1,286	3,087
41		SHELBY COUNTY CHAMBER OF COMMERCE	150	107	257
42		SPRINGDALE CHAMBER OF COMMERCE	1,800	1,286	3,086
43		TEXARKANA CHAMBER OF COMMERCE	1,500	1,071	2,571
44		VERNON PARISH CHAMBER OF COMMERCE	530	379	909
45		WALDRON AREA CHAMBER OF COMMERCE	100	71	171
46					
47		**Dues- Corporate**	**$ 327,886**	**$ 234,204**	**$ 562,090**
48	5060	AMAZON PRIME	107	77	184
49		SAM'S CLUB	100	71	171
50	9210	Arkansas Economic Developers and Chamber Execs	300	214	514
51	9302	ARKANSAS ADVANCED ENERGY ASSOCIATION	2,000	1,429	3,429
52		ARKANSAS HVACR ASSOCIATION	200	143	343
53		ASSOCIATION OF ELECTRIC COMPANIES OF TEXAS INC.	3,045	2,176	5,221
54		CAMP COUNTY CHAMBER OF COMMERCE	200	143	343
55		EAST TEXAS BUILDERS ASSOC	430	307	737
56		EDISON ELECTRIC INSTITUTE	309,174	220,838	530,012
57		HOME BUILDERS ASSOCIATION OF NORTHWEST LOUISIANA	500	357	857
58		HOME BUILDERS ASSOCIATION OF TEXARKANA	465	332	797

Southwestern Electric Power Company **SCHEDULE C-6**
Other Expenditures
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Disclosure of all expenditures in support of or membership in social, recreational, fraternal, religious clubs or organizations, Chambers of Commerce, and civic associations, lobbying or charitable contributions which are included in the test year utility operating expense. Include these expenditures for the utility, as well as the service company or other affiliate, if included in test year utility operating expense.

(1) Line No.	(2) Account Number	(3) Expenditure Description	(4) Actual Test Year Booked Amount	(5) Projected Portion of Test Year Amount	(6) Total Amount
59		LOUISIANA HEAT PUMP ASSOCIATION	400	286	686
60		NORTHWEST ARKANSAS HOMEBUILDERS ASSOC	450	321	771
61		NORTHWEST LOUISIANA MANUFACTURING MANAGERS COL	600	429	1,029
62		SAM'S CLUB	110	78	188
63		SHREVEPORT ASSOCIATION OF BUILDING OWNERS AND M/	460	329	789
64		SHREVEPORT-BOSSIER MILITARY AFFAIRS COUNCIL	825	589	1,414
65		SOUTHEASTERN WIND COALITION	5,000	3,571	8,571
66		TEXAS WATER CONSERVATION ASSOC	3,520	2,514	6,034
67					
68					
69		**Dues - Employee**	**$ 2,654**	**$ 1,899**	**$ 4,552**
70					
71	5140	ARKANSAS BOILER ASSOCIATION	168	120	288
72	5800	LOUISIANA ENGINEERING SOCIETY	78	56	133
73		NATIONAL SOCIETY OF PROFESSIONAL ENGINEERS	77	55	132
74	5880	AMERICAN SOCIETY FOR TESTING AND MATERIALS	60	43	103
75		OKLAHOMA BOARD OF PROFESSIONAL ENGINEERS AND LA	67	48	115
76	5900	LOUISIANA ENGINEERING SOCIETY	78	56	133
77		NATIONAL SOCIETY OF PROFESSIONAL ENGINEERS	77	55	132
78	5930	TEXAS DEPARTMENT OF AGRICULTURE	143	103	246
79	9080	ARKANSAS ASSOCIATION OF ENERGY ENGINEERS	185	132	317
80		ARKANSAS WOMEN IN POWER	25	18	43
81	9210	ASSOCIATION OF ENERGY ENGINEERS	160	114	274
82		ASSOCIATION OF ENERGY SERVICES PROFESSIONALS	425	304	729
83		AMERICAN ASSOCIATION OF PROFESSIONAL LANDMEN	125	89	214
84		AMERICAN SOCIETY OF MINING AND RECLAMATION	32	23	55
85		ARKANSAS PRESS ASSOCIATION	225	161	386
86		ARKANSAS WOMEN IN POWER	25	18	43
87		ASSOCIATION OF LOUISIANA LOBBYISTS	300	214	514
88		LOUISIANA PRESS ASSOCIATION	200	143	343
89		PUBLIC RELATIONS ASSOCIATION OF LOUISIANA	70	50	120
90		TEXAS BOARD OF ENGINEERS	40	29	69
91		TOASTMASTERS	45	32	77
92	9302	EAST TEXAS CITY MANAGERS ASSOCIATION	50	36	86
93					
94		**Economic Development**	**$ 11,170**	**$ 7,980**	**$ 19,150**
95	9210	INTERNATIONAL ECONOMIC DEV COUNCIL	420	300	720
96	9302	ARKANSAS ECONOMIC DEVELOPERS	600	429	1,029
97		BOONEVILLE DEVELOPMENT CORP	500	357	857
98		ENID REGIONAL DEVELOPMENT ALLIANCE INC	750	536	1,286
99		GREATER BOSSIER ECON DEV FOUND	1,000	714	1,714
100		LOUISIANA INDUSTRIAL DEVELOPMENT	250	179	429
101		NEVADA COUNTY INDUSTRIAL DEVELOPMENT	250	179	429
102		NORTHEAST TEXAS ECONOMIC DEVELOPMENT CORP.	50	36	86
103		NORTHWEST ARKANSAS COUNCIL	5,500	3,929	9,429
104		NORTHWEST OKLAHOMA ALLIANCE	1,000	714	1,714
105		PANOLA COUNTY DEVELOPMENT FOUNDATION	100	71	171
106		SOUTHERN ECONOMIC DEVELOPMENT COUNCIL	250	179	429
107		SOUTHWEST ARKANSAS DEVELOPMENT ALLIANCE	500	357	857
108					
109		**Legislative**	**$ 5,700**	**$ 4,071**	**$ 9,771**
110	930.2	LOUISIANA ASSOCIATION OF BUSINESS AND INDUSTRY	5,700	4,071	9,771
111					
112		**Grand Total**	**$ 379,415**	**$ 271,012**	**$ 650,426**

Note: amounts included in totals on C-1 and C-2.

Southwestern Electric Power Company **SCHEDULE C-6**
Other Expenditures - AEPSC
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Disclosure of all expenditures in support of or membership in social, recreational, fraternal, religious clubs or organizations, Chambers of Commerce, and civic associations, lobbying or charitable contributions which are included in the test year utility operating expense. Include these expenditures for the utility, as well as the service company or other affiliate, if included in test year utility operating expense.

(1) Line No.	(2) Account Number	(3) Expenditure Description	(4) Actual Test Year Booked Amount (A)	(5) Projected Portion of Test Year Amount	(6) Total Amount
1		**Community Relations**	**5**	**4**	**9**
2	9230	COLUMBUS ZOO AND AQUARIUM	5	4	9
				-	-
3		**Dues- Chamber of Commerce**	**34,820**	**24,871**	**59,691**
4	9302	UNITED STATES CHAMBER OF COMMERCE	34,820	24,871	59,691
				-	-
5		**Dues- Corporate**	**131,925**	**94,231**	**226,154**
6	5660	NORTH AMERICAN TRANSMISSION FORUM INC	34,278	24,485	58,763
7	9210	AMERICAN BENEFITS COUNCIL	550	393	943
8		SHAREHOLDER SERVICES ASSOCIATION	95	68	163
9	9302	ALLIANCE FOR TRANSPORTATION	2,882	2,059	4,941
10		AMERICAN WIND ENERGY ASSOCIATION	922	659	1,581
11		CARNEGIE MELLON UNIVERSITY	5,764	4,117	9,881
12		CENTER FOR ENERGY WORKFORCE DEVELOPMENT	3,459	2,470	5,929
13		CLEAN AFFORDABLE RELIABLE ELECTRICITY	9,229	6,592	15,821
14		COAL UTILIZATION RESEARCH COUNCIL	268	191	459
15		COMMITTEE OF 200	208	149	357
16		ENERGY STORAGE ASSOCIATION	671	480	1,151
17		MIDWEST COAL ASH ASSOCIATION	185	132	317
18		NATIONAL ASSOCIATION OF MANUFACTURERS	11,945	8,532	20,477
19		NATIONAL COAL COUNCIL	2,151	1,536	3,687
20		NORTH AMERICAN ENERGY MARKETS ASSOCIATION	1,108	791	1,899
21		NORTH AMERICAN ENERGY STANDARDS BOARD	851	607	1,458
22		SECURITIES TRANSFER ASSN INC	116	83	199
23		SMART ELECTRIC POWER ALLIANCE	3,430	2,450	5,880
24		SOCIAL MEDIA ORG	1,729	1,235	2,964
25		SUSTAINABILITY INC	2,306	1,647	3,953
26		UNITED STATES ENERGY ASSOCIATION	576	411	987
27		WILDLIFE HABITAT COUNCIL INC	1,729	1,235	2,964
28		WORLD RESOURCES INSTITUTE	8,646	6,176	14,822
29		AMERICAN COALITION FOR CLEAN COAL ELECTRICITY	10,570	7,550	18,120
30		ARIZONA STATE UNIVERSITY- POWER SYSTEMS ENGINEERING RESEARCH CENTER	3,671	2,622	6,293
31		BOSTON COLLEGE/CENTER FOR CORPORATE CITIZENSHIP	1,150	821	1,971
32		CENTER FOR ENERGY MANAGEMENT THROUGH TECHNOLOGICAL INNOVATION	12,500	8,929	21,429
33		GLOBAL LISTED INFRASTRUCTURE ORGANIZATION	2,025	1,447	3,472
34		NATIONAL ASSOCIATION FOR ENVIRONMENTAL MANAGEMENT	763	545	1,308
35		WOMEN FOR ECONOMIC & LEADERSHIP DEVELOPMENT	-	-	-
36		WIRES (WORKING GROUP FOR INVESTMENT IN RELIABLE AND ECONOMIC ELECTRIC SYSTEMS)	8,146	5,819	13,965
37		**Dues-Employee**	**6,252**	**4,465**	**10,723**
38	5000	AIR AND WASTE MANAGEMENT ASSOCIATION	96	68	164
39		AMERICAN CONCRETE INSTITUTE	239	171	410
40		ARKANSAS BOILER ASSOCIATION	22	15	37
41		ASM INTERNATIONAL	25	18	42
42		ASSOCIATION OF STATE DAM SAFETY OFFICIALS	22	16	38
43		NATL BOARD OF BOILER AND PRESSURE VESSEL INSPECTORS	11	9	20
44		TOASTMASTERS	32	23	55
45		AMERICAN ASSOCIATION OF BLACKS IN ENERGY	65	46	111
46		ENVIROCERT INTERNATIONAL	58	42	100
47		POWER PLANT & ENVIRONMENTAL CHEMISTRY COMMITTEE	142	101	243
48		INTERNATIONAL SOCIETY OF AUTOMATION	60	43	103
49		KENTUCKY BOARD OF ENGINEERS AND LAND SURVEYORS	75	54	129
50		OHIO ENGINEERS AND SURVEYORS BOARD	22	16	38
51		PROJECT MGMT INSTITUTE	311	222	533
52		SOCIETY OF ENVIRONMENTAL TOXICOLOGY AND CHEMISTRY	36	25	61
53		WORLD SAFETY ORGANIZATION	6	4	10
54	5060	NATIONAL SOCIETY OF PROFESSIONAL ENGINEERS	78	56	134
55		OHIO ENGINEERS AND SURVEYORS BOARD	9	6	15
56		PROJECT MGMT INSTITUTE	70	50	120
57		TEXAS BOARD OF ENGINEERS	9	6	15
58	5570	AICPA ORDER	39	28	67
59		NERC	70	50	120
60		TOASTMASTERS	10	7	17
61	5600	AMERICAN SOCIETY OF SAFETY ENGINEERS	13	9	22
62		DC BAR	20	15	35
63		INDIANA PROFESSIONAL LICENSING AGENCY	29	21	50
64		NERC	75	54	129
65		TOASTMASTERS	22	15	37
66		AMERICAN SOCIETY FOR CIVIL ENGINEERS	16	11	27

Southwestern Electric Power Company
Other Expenditures - AEPSC
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE C-6

Explanation: Disclosure of all expenditures in support of or membership in social, recreational, fraternal, religious clubs or organizations, Chambers of Commerce, and civic associations, lobbying or charitable contributions which are included in the test year utility operating expense. Include these expenditures for the utility, as well as the service company or other affiliate, if included in test year utility operating expense.

(1) Line No.	(2) Account Number	(3) Expenditure Description	(4) Actual Test Year Booked Amount (A)	(5) Projected Portion of Test Year Amount	(6) Total Amount
67		ANNUAL PROFESSIONAL ENGINEER FEE	13	9	22
68		BOARD OF CERTIFIED SAFETY PROFESSIONALS	27	19	46
69		BOARD OF RFPE & LAND SURVEYORS	23	16	39
70		INSTITUTE OF ELECTRICAL AND ELECTRONICS ENGINEERS	88	64	152
71		AEIC PROJECT MANAGEMENT SUBCOMMITTEE	16	12	28
72		NATIONAL COUNCIL OF EXAMINERS FOR ENGINEERING & SURVEYING	64	46	110
73		OHIO ENGINEERS AND SURVEYORS BOARD	14	10	24
74		INTERNATIONAL ASSOCIATION FOR PUBLIC PARTICIPATION	9	6	15
75		WOMEN'S INTERNATIONAL NETWORK OF UTILITY PROFESSIONALS	12	9	21
76		PROJECT MGMT INSTITUTE	492	351	843
77		TEXAS BOARD OF ENGINEERS	3	2	5
78		VA DEPARTMENT OF PROFESSIONAL & OCCUPATIONAL REGULATION (PROF. ENG. LICENSE)	10	8	18
79		WOMEN FOR ECONOMIC & LEADERSHIP DEVELOPMENT	8	6	14
80		WV TREASURY (ASBESTOS LICENSING APPLICATION FOR INDIVIDUALS)	7	4	11
81	5612	NERC	89	64	153
82	5660	TESTMASTERS	64	46	110
83		TOASTMASTERS	6	4	10
84		AMERICAN SOCIETY FOR CIVIL ENGINEERS	16	12	28
85		CIAPR SODALIS (PROFESSIONAL ENGINEER FEES)	13	9	22
86		INSTITUTE OF ELECTRICAL AND ELECTRONICS ENGINEERS	6	5	11
87		NATIONAL COUNCIL OF EXAMINERS FOR ENGINEERING & SURVEYING	25	18	43
88		NATIONAL SOCIETY OF PROFESSIONAL ENGINEERS	20	14	34
89		OHIO ENGINEERS AND SURVEYORS BOARD	29	21	50
90		PROJECT MGMT INSTITUTE	40	28	68
91		TEXAS BOARD OF PROFESSIONAL ENGINEERS	3	1	4
92		VA DEPARTMENT OF PROFESSIONAL & OCCUPATIONAL REGULATION (PROF. ENG. LICENSE)	5	3	8
93	5710	INTERNATIONAL SOCIETY OF ARBORICULTURE	25	17	42
94		UTILITY ARBORIST ASSOCIATION	2	2	4
95	5800	BOARD OF RFPE & LAND SURVEYORS	15	11	25
96		NATL FIRE PROTECTION ASSOC.	17	12	29
97	5860	OHIO ENGINEERS AND SURVEYORS BOARD	5	4	9
98	5880	AICPA ORDER	44	31	75
99		UTILITY ARBORIST ASSOCIATION	1	1	2
100	9050	EPAY RESOURCES	43	31	74
101	9120	WOMEN'S INTERNATIONAL NETWORK OF UTILITY PROFESSIONALS	8	6	14
102		UTILITY ECONOMIC DEVELOPMENT ASSOCIATION	77	55	132
103	9210	ACCOUNTANCY BOARD	164	117	281
104		AICPA ORDER	117	83	200
105		AMERICAN BAR ASSOCIATION	64	46	110
106		AMERICAN SOCIETY OF SAFETY ENGINEERS	16	11	27
107		ASSOCIATION OF ENERGY ENGINEERS	20	13	33
108		COLUMBUS COMPENSATION ASSOCIATION	13	9	22
109		DC BAR	71	50	121
110		DRI INC CHICAGO IL	33	23	56
111		HEALTH ACTION COUNCIL	678	484	1,162
112		INDIANA PROFESSIONAL LICENSING AGENCY	25	18	43
113		INTERNATIONAL RIGHT OF WAY ASSOCIATION	28	20	48
114		KENTUCKY BAR ASSOCIATION	37	26	63
115		OHIO SOCIETY OF CPAs	77	55	132
116		OHIO STATE BAR ASSOCIATION	139	98	237
117		OKLAHOMA BAR ASSOCIATION	141	100	241
118		OKLAHOMA SOCIETY CPAS	137	98	235
119		PROSCI INC	38	27	64
120		SOCIETY OF AMERICAN FORESTERS	24	17	41
121		SOCIETY OF DEPRECIATION PROFESSIONALS	19	14	33
122		STATE BAR TX-DUES-WEB	371	265	636
123		STATE OF MI LICENSING	19	13	32
124		TOASTMASTERS	6	4	10
125		TREASURER OF VIRGINIA	3	2	5
126		VIRGINIA BOARD OF ACCOUNTANCY	6	4	10
127		VIRGINIA STATE BAR	32	22	54
128		WORLDATWORK	22	16	38
129		AMERICAN ASSOCIATION OF BLACKS IN ENERGY	32	23	55
130		ASSOCIATION OF CERTIFIED FRAUD EXAMINERS	26	19	45
131		AMERICAN INDUSTRIAL HYGIENE ASSOCIATION	65	46	111
132		ASSOCIATION OF CORPORATE COUNSEL	23	17	40
133		ASSOCIATION FOR TALENT DEVELOPMENT	22	16	38
134		BOARD OF CERTIFIED SAFETY PROFESSIONALS	53	38	91
135		DC BAR	6	5	11
136		PENNSYLVANIA ATTORNEY REGISTRATION	26	19	45
137		EXECUTIVE WOMEN'S INTERNATIONAL	91	65	156

Explanation: Disclosure of all expenditures in support of or membership in social, recreational, fraternal, religious clubs or organizations, Chambers of Commerce, and civic associations, lobbying or charitable contributions which are included in the test year utility operating expense. Include these expenditures for the utility, as well as the service company or other affiliate, if included in test year utility operating expense.

(1) Line No.	(2) Account Number	(3) Expenditure Description	(4) Actual Test Year Booked Amount (A)	(5) Projected Portion of Test Year Amount	(6) Total Amount
138		NATIONAL SOCIETY OF PROFESSIONAL ENGINEERS	27	19	46
139		NATIONAL INSURANCE PRODUCER REGISTRY	4	3	7
140		NORTHEAST INDIANA HUMAN RESOURCES ASSOCIATION	17	12	29
141		NEW YORK STATE ATTY REGISTRATION	44	31	75
142		OHIO ENGINEERS AND SURVEYORS BOARD	9	6	15
143		PA ATTY. REGISTRATION	12	9	21
144		CENTRAL OHIO AMERICAN INDUSTRIAL HYGIENE ASSOCIATION	2	2	4
145		COASTAL BEND SOCIETY FOR HUMAN RESOURCE MANAGEMENT	5	4	9
146		INDIANA INDUSTRY LIAISON GROUP	10	8	18
147		LEADERSHIP COLUMBUS	6	4	10
148		NORTH TEXAS AMERICAN INDUSTRIAL HYGIENE ASSOCIATION	17	12	29
149		PROJECT MGMT INSTITUTE	27	19	46
150		SOCIETY OF CORPORATE COMPLIANCE AND ETHICS	23	17	40
151		SOCIETY FOR HUMAN RESOURCE MANAGEMENT	35	25	60
152		TEXAS STATE BOARD OF PUBLIC ACCOUNTANTS	30	21	51
153		TULSA AREA HUMAN RESOURCES ASSOCIATION	13	9	22
154		TX DEPT. OF INSURANCE	7	5	12
155		WV TREASURY (ASBESTOS LICENSING APPLICATION FOR INDIVIDUALS)	14	10	24
156		ARMA INTERNATIONAL	13	9	22
157	9230	AICPA ORDER	32	23	55
158		ASSOCIATION OF STATE DAM SAFETY OFFICIALS	18	13	31
159		TOASTMASTERS	4	3	7
160		ARMA INTERNATIONAL	12	8	20
161	9250	BOARD OF RFPE & LAND SURVEYORS	13	9	22
162	9260	TOASTMASTERS	2	1	3
163	9302	AICPA ORDER	23	17	40
164		INSTITUTE OF ELECTRICAL AND ELECTRONICS ENGINEERS	77	55	132
165		NEW YORK STATE ATTY REGISTRATION	46	32	78
166		OHIO ENGINEERS AND SURVEYORS BOARD	2	1	3
167		OKLAHOMA STATE BOARD FOR PROFESSIONAL ENGINEERS	19	14	33
168		WOMEN'S INTERNATIONAL NETWORK OF UTILITY PROFESSIONALS	9	6	15
169		PROJECT MGMT INSTITUTE	24	17	41
170		**Legislative**	**9,134**	**2,809**	**6,742**
171	9210	EDISON ELECTRIC INST. (GOV. AFFAIRS CONFERENCE)	13	9	22
172		RIPON SOCIETY	3,933	2,809	6,742
173	9302	BUSINESS ROUNDTABLE	5,188	3,706	8,894
174		**Other**	**25,011**	**17,869**	**42,878**
175	5000	CRAVINGS CARRYOUT CAFE	40	29	69
176		DELTA	28	21	49
177		OFFICEMAX/OFFICEDEPT#6	38	27	65
178		SAMS CLUB	50	36	86
179		SOUTHWEST	44	31	75
180		SPEEDWAY	33	24	57
181	5060	AMERICAN	9	6	15
182		IDENTOGO - TX FINGERPR	69	49	118
183		MCDONALD'S F15746	9	7	16
184	5600	AMAZON MKTPLACE PMTS	10	7	17
185		GIANT EAGLE #6528	3	2	5
186		OFFICE DEPOT #1079	13	10	23
187		PEOPLEFACTS LLC	2	1	3
188		REES FLOWERS AND FINE GIFTS	3	2	5
189		SZECHUAN	17	12	29
190		NATIONAL COUNCIL OF EXAMINERS FOR ENGINEERING & SURVEYING	52	38	90
191	5660	ELECTRICAL PE REVIEW	57	41	98
192		SCHLOTZSKY'S 1413- E 7	3	2	5
193		AMAZON - POWER PE, LLC	6	5	11
194	5800	DONATOS PIZZERIA #0186	11	7	18
195	9030	ORACLE UTILITIES METER DATA MANAGEMENT USERS GROUP	15	11	26
196	9120	LINKEDIN-367 9095554	25	17	42
197		OUTBACK 4471	7	6	13
198	9210	AEP SODEXO	11	8	19
199		DELTA	55	40	95
200		EXECUTIVE COFFEE	99	71	170
201		LAZ PARKING 690414	18	13	31
202		METRO FARE AUTOLOAD	10	7	17
203		NATION PARKING LLC	68	49	117
204		SAMS CLUB	6	4	10
205		SOUTHWEST	22	16	38
206		UBER	28	20	48
207	9302	GUIDE STAR	751	537	1,288
208		INNOGY NEW VENTURES LLC	23,213	16,581	39,794

Explanation: Disclosure of all expenditures in support of or membership in social, recreational, fraternal, religious clubs or organizations, Chambers of Commerce, and civic associations, lobbying or charitable contributions which are included in the test year utility operating expense. Include these expenditures for the utility, as well as the service company or other affiliate, if included in test year utility operating expense.

(1) Line No.	(2) Account Number	(3) Expenditure Description	(4) Actual Test Year Booked Amount (A)	(5) Projected Portion of Test Year Amount	(6) Total Amount
209		MX INDUSTRIAL DISTRIBU	184	132	316
210		**Sponsorship**	**3,817**	**2,726**	**6,543**
211	9302	AHC GROUP INC-ENERGY COMPETITIVENESS WORKING GROUP SPONSOR 2018	3,817	2,726	6,543
212		**Grand Total**	**210,964**	**146,975**	**352,740**

Note: amounts included in totals on C-1 and C-2.

Southwestern Electric Power Company **SCHEDULE C-7**
Advertising and Marketing
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Disclosure of all expenditures for advertising or marketing which are included in the test year utility operating expense. Include any of these expenditures for the utility, as well as the service company or other affiliate, if included in test year utility operating expense.

(1) Line No.	(2) Account Number	(3) Expenditure Description and Purpose	(4) Actual Test Year Booked Amount Jan '18 - July '18	(5) Projected Portion of Test Year Amount Aug '18 - Dec '18	(6) Total Projected Test Year Amount (A) Jan '18 - Dec '18	Recovery
1	909	Affiliate billings	$ 193	$ -	$ 193	recoverable
2		Forecasted Activity		14,260	14,260	recoverable
3	909	TOTAL	$ 193	$ 14,260	$ 14,453	
4	930.1	Safety - National Theater for Children	$ 50,250	$ -	$ 50,250	recoverable
5		Safety	9,100	-	9,100	recoverable
6		Brand Expenses	14,565	-	14,565	promotional - removed
7		Energy Efficiency	1,709	-	1,709	rider - removed
8		Wind Advertising	4,545	-	4,545	removed
9		Mutual Assistance	1,491	-	1,491	removed
10		Customer Information - phonebooks	25,176	-	25,176	recoverable
11		Customer information - mobile app	11,125	-	11,125	recoverable
12		Customer information	6,780	-	6,780	recoverable
13		Customer Surveys	12,619	-	12,619	recoverable
14		Administration	10,085	-	10,085	recoverable
15		Affiliate bilings	24,459	-	24,459	recoverable
16		Customer information - valley usage	100	-	100	removed
17		Forecasted activity		86,796	86,796	recoverable
18	930.1	TOTAL	$ 172,004	$ 86,796	$ 258,800	(a) (B)
19		TOTAL ACCOUNT 909 & 930.1	172,197	101,056	273,253	

Supporting Schedules:
(a) Schedule E-17A

Recap Schedules
(A) WP C 2-24
(B) Schedule C-3

Southwestern Electric Power Company **SCHEDULE C-8**
Taxes Other than Income Taxes
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: A schedule showing, by major category and state, all taxes other than income charged to operating expense for the test year and pro forma year.

(1)	(2)	(3)	(4)	(5)
Line No.	Subaccount Number	Description	Test Year (b) (A)	Adjusted Pro Forma Year (a) (A)
1	4081002	FICA	10,876,194	10,902,054
2	4081003	Federal Unemployment Tax	58,748	58,748
3	408100517	Real Personal Property Taxes	(911,696)	0
4	408100518	Real Personal Property Taxes	64,201,415	0
5	408100519	Real Personal Property Taxes		62,177,492
6	408100617	State Gross Receipts Tax	2	
7	408100618	State Gross Receipts Tax	6,037,591	6,037,487
8	4081007	State Unemployment Tax	79,692	79,692
9	408100818	State Franchise Taxes	5,165,951	5,165,951
10	408101417 & 408101418	Federal Excise Taxes	925	925
11	408101717	St Lic-Rgstrtion Tax-Fees	14,575	14,575
12	408101718	St Lic-Rgstrtion Tax-Fees	17,070	17,070
13	408101817	St Publ Serv Comm Tax-Fees	731,125	731,125
14	408101818	St Publ Serv Comm Tax-Fees	1,252,714	1,252,714
15	408101900	State Sales and Use Taxes	(311,500)	0
16	408101916	State Sales and Use Taxes	185,277	0
17	408101917	State Sales and Use Taxes	246	0
18	408101918	State Sales and Use Taxes	4,876	0
19	408102218	Municipal License Fees	80,475	80,475
20	408102318	Local Privilege-Franchise Tax	18,005,587	18,005,587
21	408102917	Real-Pers Prop Tax-Cap Leases	9,469	0
22	408102918	Real-Pers Prop Tax-Cap Leases	143,834	143,834
23	4081033	Fringe Benefit Loading - FICA	(3,379,244)	(3,379,244)
24	4081034	Fringe Benefit Loading - FUT	(19,508)	(19,508)
25	4081035	Fringe Benefit Loading - SUT	(30,557)	(30,557)
26	Grand Total		102,213,261	101,238,420

27	**Ad Valorem Taxes Liability for 2018 Tax Year. This amount represents the 2018 liability not the amount expensed in the calendar year.	
28	Arkansas	15,200,000
29	Louisiana	25,628,710
30	Oklahoma	451,464
31	Texas	21,516,788
32	Total **	62,796,962
33	See WP C 2-17 for tax category summary.	

Supporting Schedules and Workpapers:
(a) WP C 2-17
(b) Schedule E-17A

Recap Schedules:
(A) Schedule C-1

Southwestern Electric Power Company
Investment Tax Credits
Test Year Ending December 31, 2018
Docket No. 19-008-U

Schedule C-9

Explanation: A Schedule showing the calculation of the total company Investment Tax Credits (ITC) realized in the test year and pro forma year and ratable amortization of accumulated investment tax credits to operating income.

			Total Company	
Line No.	**Description**		**Test Year (A)**	**Pro Forma Test Year (A)**
1.	ITC recognized in the current year.			
2.	Ratable portion of Post 1970 accumulated deferred investment tax credits (Credit)	(a)	(1,244,396)	(386,757)
3.	Total Post 1970 accumulated deferred investment tax credits (Credit)	(b)	(4,661,859)	(4,275,102)
4.	Ratable portion of Pre 1971 accumulated deferred investment tax credits		-	-
5.	Total Pre 1971 accumulated deferred investment tax credits		-	-

Supporting Schedules:
(a) Schedule E-17A
(b) Schedule E-17B

Recap Schedules
(A) WP C 2-26

Southwestern Electric Power Company
Accumulated Deferred Income Taxes
Test Year Ending December 31, 2018
Docket No. 19-008-U

Schedule C-10

Explanation: A schedule showing the total company balances of Accumulated Deferred Income Taxes (ADIT) as of the end of the historical test year or the historical portion of a projected test year and pro forma year end. Further, distinguish between depreciation related ADIT and non-depreciation related ADIT.

		Total Company		
Line No.	**Description**	**Test Year (a)**		**Balance at end Pro Forma Test Year (a)**
1 2	Federal Depreciation related ADIT (excluding SFAS 109 Fede and State ADIT)	(1,204,710,417)		(1,094,158,634)
3	Federal Non-Depreciation related ADIT (excluding SFAS 109 Federal and State ADIT and ADIT for OCI)	33,101,652		(29,058,660)
4 5	Total ADIT before State ADIT, SFAS 109 ADIT and ADIT for OCI	(1,171,608,765)		(1,123,217,294)
6	State ADIT (excluding SFAS 109 State ADIT)	47,097,817		-
7	Federal ADIT for OCI	1,209,014		-
8	Total ADIT (before SFAS 109 Federal and State ADIT)	(1,123,301,934)		(1,123,217,294)
9	SFAS 109 ADIT:			
10	Federal - Depreciation related	515,741,054		530,601,183
11	Federal - Non-Depreciation related	125,973,099		131,193,260
12	State	(192,468,603)		(189,647,257)
13	TOTAL SFAS 109 Federal and State ADIT	449,245,550		472,147,186
14	**Total ADIT Included in Schedule D 1.2 & D 1.3**	**(674,056,384)** (B)	(C)	**(651,070,108)** (A), (D)

Supporting Schedules:
(a) WP C-10-1

Recap Schedules
(A) Schedule D-1.3
(B) Schedule D-1.2
(C) Schedule D-5.2
(D) Schedule D-5.3

Southwestern Electric Power Company
Accumulated Deferred Income Taxes
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP C-10-1

ACCOUNT	NON-DEPRECIATION RELATED ADIT (a) (b)	DEPRECIATION RELATED ADIT (a) (b)	TOTAL COMPANY ADIT @ 12/31/18	TOTAL COMPANY GOING-LEVEL ADJUSTMENTS (a) (b)	ADJUSTED TOTAL COMPANY ADIT @ 12/31/19 (A)
ACCOUNT 190					
1901001 Accumulated Deferred FIT - Other	(65,590,228)	0	(65,590,228)	78,463,797	12,873,569
1901002 Deferred SIT	(47,097,817)		(47,097,817)	47,097,817	0
1902001 Accum DFIT - Other Income & Deducti	(673,975)	0	(673,975)	673,975	0
1903001 Accum DFIT - FAS 109 Flow-Thru	(41,633,476)	0	(41,633,476)		(41,633,476)
1904001 Accum DFIT - FAS 109 Excess	(148,407,966)	0	(148,407,966)		(148,407,966)
1900011 ADIT Federal - Pension OCI NAf	417,286	0	417,286	(417,286)	0
1900015 ADIT-Fed-Hdg-CF-Int Rate	(1,626,300)	0	(1,626,300)	1,626,300	0
Total Account 190	(304,612,476)	0	(304,612,476)	127,444,603	(177,167,873)
	(304,612,476)				
ACCOUNT 281					
2811001 Accumulated Deferred FIT - Accell Amo	0	68,316,218	68,316,218	(42,843,666)	25,472,552
2814001 Accumulated Deferred - FAS 109 Exces	0	(27,152,794)	(27,152,794)	(782,358)	(27,935,152)
Total Account 281	0	41,163,424	41,163,424	(43,626,024)	(2,462,600)
ACCOUNT 282					
2821001 Accumulated Deferred FIT - Utility Prop	0	1,136,394,199	1,136,394,199	(67,708,117)	1,068,686,082
2822001 Accum DFIT - Other Income & Deducti	0	0	0	0	0
Turk ADIT Elimination					
2823001 Accum DFIT - FAS 109 Flow-Thru	0	55,443,126	55,443,126	1,597,492	57,040,618
2824001 Accum DFIT - FAS 109 Excess	0	(544,031,386)	(544,031,386)	(15,675,263)	(559,706,649)
Total Account 282	0	647,805,939	647,805,939	(81,785,888)	566,020,051
ACCOUNT 283					
2830016 ADIT-Fed-Hdg-CF-For Exchg			0	0	0
2831001 Accumulated Deferred FIT - Other	33,162,551		33,162,551	(16,977,460)	16,185,091
2831002 Accumulated Deferred SIT - Other			0		0
2832001 Accum DFIT - Other Income & Deductions			0	0	0
2833001 Accum DFIT - FAS 109 Flow-Thru	55,116,691		55,116,691	(5,220,161)	49,896,530
2833002 Accum DSIT - FAS 109 Flow-Thru	192,468,603		192,468,603	(2,821,346)	189,647,257
2834001 Accum DFIT - FAS 109 Excess	8,951,652		8,951,652		8,951,652
Total Account 283	289,699,497	0	289,699,497	(25,018,967)	264,680,530
			289,699,497	(25,018,967)	264,680,530
TOTAL ACCUMULATED DEFERRED INCOME	(14,912,979)	688,969,363	674,056,384	(22,986,276)	651,070,108

Supporting Schedules:
(a) WP C-10-4
(b) WP C-10-5

Recap Schedules:
(A) Schedule C-10

Southwestern Electric Power Company
Accumulated Deferred Income Taxes - Total
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP C-10-2

Effective State Tax Rate 0.046779

For the Period: Jan 2018 thru Jul 2018 Actual, Aug-De	January - July 2018	Forecasted Aug - December 2018	7 Months Actual Plus 5 Months Forecasted 2018	Federal Tax Effect	(AR, OK, LA, NE) State Tax Effect (4.6779%)	Total Tax Effect (25.6779%)
==						
Book Income	93,742,329.51	65,349,084.00	159,091,413.51	33,409,196.84	7,442,137.23	40,851,334.07
Tax Items	-		-			
Book Income Before Tax	93,742,329.51	65,349,084.00	159,091,413.51	33,409,196.84	7,442,137.23	40,851,334.07
==						
EXCESS TAX vs BOOK DEPRECIATION						
230A ACRS BENEFIT NORMALIZED	7,644,000.00	(8,351,000.00)	(707,000.00)	(148,470.00)	(33,072.75)	(181,542.75)
280A EXCESS TX VS S/L BK DEPR	3,780,000.00	2,920,000.00	6,700,000.00	1,407,000.00	313,419.30	1,720,419.30
280H BK PLANT IN SERVICE - SFAS 143 - ARO	(23,154,213.88)	1,011,000.00	(22,143,213.88)	(4,650,074.91)	(1,035,837.40)	(5,685,912.31)
390A CIAC - BOOK RECEIPTS	1,261,037.94	1,123,000.00	2,384,037.94	500,647.97	111,522.91	612,170.88
Total EXCESS TAX vs BOOK DEPRECIATION	(10,469,175.94)	(3,297,000.00)	(13,766,175.94)	(2,890,896.94)	(643,967.94)	(3,534,864.88)
==						
AFUDC / INTEREST CAPITALIZED						
320A ABFUDC	(3,242,825.59)	(2,979,000.00)	(6,221,825.59)	(1,306,583.37)	(291,050.78)	(1,597,634.15)
330D AFUDC CAPITALIZED	(3,368,465.65)	(3,930,000.00)	(7,298,465.65)	(1,532,677.79)	(341,414.92)	(1,874,092.71)
380J INT EXP CAPITALIZED FOR TAX	4,849,619.62	2,694,000.00	7,543,619.62	1,584,160.12	352,882.98	1,937,043.10
Total AFUDC / INTEREST CAPITALIZED	(1,761,671.62)	(4,215,000.00)	(5,976,671.62)	(1,255,101.04)	(279,582.72)	(1,534,683.76)
==						
PERCENT REPAIR ALLOWANCE						
532C BOOK/TAX UNIT OF PROPERTY ADJ	(31,549,000.00)	(32,441,000.00)	(63,990,000.00)	(13,437,900.00)	(2,993,388.21)	(16,431,288.21)
532D BOOK/TAX UNIT OF PROPERTY ADJ-SEC 48	3,353,000.00	117,000.00	3,470,000.00	728,700.00	162,323.13	891,023.13
534A CAPITALIZED RELOCATION COSTS	(1,988,000.00)	(1,420,000.00)	(3,408,000.00)	(715,680.00)	(159,422.83)	(875,102.83)
Total PERCENT REPAIR ALLOWANCE	(30,184,000.00)	(33,744,000.00)	(63,928,000.00)	(13,424,880.00)	(2,990,487.91)	(16,415,367.91)
==						
REMOVAL COSTS						
910K REMOVAL CST	(12,401,000.00)	(8,804,000.00)	(21,205,000.00)	(4,453,050.00)	(991,948.70)	(5,444,998.70)
Total REMOVAL COSTS	(12,401,000.00)	(8,804,000.00)	(21,205,000.00)	(4,453,050.00)	(991,948.70)	(5,444,998.70)
==						
ACCELERATED AMORTIZATION						
533A TX AMORTIZATION POLLUTION CONTROL E	(2,877,000.00)	-	(2,877,000.00)	(604,170.00)	(134,583.18)	(738,753.18)
533J TX ACCEL AMORT-CAPITALIZED SOFTWARE	(483,000.00)	-	(483,000.00)	(101,430.00)	(22,594.26)	(124,024.26)
Total ACCELERATED AMORTIZATION	(3,360,000.00)	-	(3,360,000.00)	(705,600.00)	(157,177.44)	(862,777.44)
==						
MINE DEVELOPMENT						
921A BK DEPLETION-MINERALS & RIGHTS	1,006,997.38	(6,399,000.00)	(5,392,002.62)	(1,132,320.55)	(252,232.49)	(1,384,553.04)
921G ACCEL BOOK DEPLETION	(8,400,000.00)	(6,792,000.00)	(15,192,000.00)	(3,190,320.00)	(710,666.57)	(3,900,986.57)
Total MINE DEVELOPMENT	(7,393,002.62)	(13,191,000.00)	(20,584,002.62)	(4,322,640.55)	(962,899.06)	(5,285,539.61)
==						
REVENUE REFUNDS						
520A PROVS POSS REV REFDS	1,611,191.29	-	1,611,191.29	338,350.17	75,369.92	413,720.09
520X PROV FOR RATE REFUND-TAX REFORM	29,008,073.17	-	29,008,073.17	6,091,695.37	1,356,968.65	7,448,664.02
520Y PROV FOR RATE REFUND-EXCESS PROTEC	8,184,184.92	-	8,184,184.92	1,718,678.83	382,847.99	2,101,526.82
Total REVENUE REFUNDS	38,803,449.38	-	38,803,449.38	8,148,724.37	1,815,186.56	9,963,910.93
==						
DEFERRED FUEL COSTS						
433A PUCT FUEL O/U RECOVERY-RETAIL	-	-	-	-	-	-
433B INTEREST-FUEL OVER/UNDER RECOVERY	-		-	-	-	-
433C AR - FUEL OVER/UNDER RECOVERY	(1,966,281.83)	16,349,000.00	14,382,718.17	3,020,370.82	672,809.17	3,693,179.99
433D LA - FUEL OVER/UNDER RECOVERY	(3,227.00)	-	(3,227.00)	(677.67)	(150.96)	(828.63)
Total DEFERRED FUEL COSTS	(1,969,508.83)	16,349,000.00	14,379,491.17	3,019,693.15	672,658.21	3,692,351.36
==						
EQUITY IN EARNINGS OF SUBSIDIARIES						
531A EQTY IN SUBSIDIARIES (US)	(18,290.05)	-	(18,290.05)	(3,840.91)	(855.59)	(4,696.50)
531B EQTY IN NON-CONSOLIDATED SUBS	(1,441,682.34)	-	(1,441,682.34)	(302,753.29)	(67,440.46)	(370,193.75)
Total EQUITY IN EARNINGS OF SUBSIDIARIES	(1,459,972.39)	-	(1,459,972.39)	(306,594.20)	(68,296.05)	(374,890.25)
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Southwestern Electric Power Company
Accumulated Deferred Income Taxes - Total
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP C-10-2

Effective State Tax Rate 0.046779

For the Period: Jan 2018 thru Jul 2018 Actual, Aug-De	January - July 2018	Forecasted Aug - December 2018	7 Months Actual Plus 5 Months Forecasted 2018	Federal Tax Effect	(AR, OK, LA, NE) State Tax Effect (4.6779%)	Total Tax Effect (25.6779%)
=======================================						
BOOK ACCRUALS						
601E INSURANCE PREMIUMS ACCRUED	-		-	-	-	-
602A PROV WORKER'S COMP	303,756.72	-	303,756.72	63,788.91	14,209.44	77,998.35
605B ACCRUED BK PENSION EXPENSE	3,941,213.58	2,169,000.00	6,110,213.58	1,283,144.85	285,829.68	1,568,974.53
605C ACCRUED BK PENSION COSTS - SFAS 158	(2,505,367.50)		(2,505,367.50)	(526,127.18)	(117,198.59)	(643,325.77)
605E SUPPLEMENTAL EXECUTIVE RETIREMENT I	50,236.68	-	50,236.68	10,549.70	2,350.02	12,899.72
605F ACCRD SUP EXEC RETIR PLAN COSTS-SFA:	(28,785.50)		(28,785.50)	(6,044.96)	(1,346.56)	(7,391.52)
605I ACCRD BK SUP. SAVINGS PLAN EXP	(99,160.73)	-	(99,160.73)	(20,823.75)	(4,638.64)	(25,462.39)
605K ACCRUED BK BENEFIT COSTS	(12,972.41)	-	(12,972.41)	(2,724.21)	(606.84)	(3,331.05)
605O ACCRUED PSI PLAN EXP	(2,200,062.36)	-	(2,200,062.36)	(462,013.10)	(102,916.72)	(564,929.82)
610A BK PROV UNCOLL ACCTS	(771,733.19)		(771,733.19)	(162,063.97)	(36,100.91)	(198,164.88)
611E ACCRUED MINE RECLAMATION	730,553.83		730,553.83	153,416.30	34,174.58	187,590.88
612Y ACCRD COMPANYWIDE INCENTV PLAN	(1,511,902.00)	2,736,000.00	1,224,098.00	257,060.58	57,262.08	314,322.66
613E ACCRUED BOOK VACATION PAY	791,254.18	-	791,254.18	166,163.38	37,014.08	203,177.46
613K (ICDP)-INCENTIVE COMP DEFERRAL PLAN	23,454.61		23,454.61	4,925.47	1,097.18	6,022.65
615B ACCRUED INTEREST-LONG-TERM - FIN 48	107,036.00	-	107,036.00	22,477.56	5,007.04	27,484.60
615C ACCRUED INTEREST-SHORT-TERM - FIN 48	4,798.00		4,798.00	1,007.58	224.45	1,232.03
Total BOOK ACCRUALS	(1,177,680.09)	4,905,000.00	3,727,319.91	782,737.16	174,360.29	957,097.45
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BOOK DEFERRALS						
615O BK DFL RAIL TRANS REV/EXP	(141.35)	-	(141.35)	(29.68)	(6.61)	(36.29)
630M RATE CASE DEFD CHGS	1,664,837.77	-	1,664,837.77	349,615.93	77,879.45	427,495.38
641I ADVANCE RENTAL INC (CUR MO)	1,131,640.20	(625,000.00)	506,640.20	106,394.44	23,700.12	130,094.56
660F REG ASSET - SFAS 143 - ARO	(779,208.67)	-	(779,208.67)	(163,633.82)	(36,450.60)	(200,084.42)
661R REG ASSET - SFAS 158 - PENSIONS	2,505,367.50		2,505,367.50	526,127.18	117,198.59	643,325.77
661S REG ASSET - SFAS 158 - SERP	28,785.50		28,785.50	6,044.96	1,346.56	7,391.52
661T REG ASSET - SFAS 158 - OPEB	(1,412,367.46)		(1,412,367.46)	(296,597.17)	(66,069.14)	(362,666.31)
664A REG ASSET-UND/REC ENVIRON ADJ CLAUS	80,107.60	-	80,107.60	16,822.60	3,747.35	20,569.95
664R REG ASSET-VALLEY DISTRICT DUE DILIGEN	33,032.03		33,032.03	6,936.73	1,545.21	8,481.94
664V REG ASSET-NET CCS FEED STUDY COSTS	23,215.80		23,215.80	4,875.32	1,086.01	5,961.33
668P REG ASSET-LA FRP ASSET	54,954.54	-	54,954.54	11,540.45	2,570.72	14,111.17
669J REG ASSET-ENERGY EFFICIENCY RECOVEF	1,782,932.41	1,360,000.00	3,142,932.41	660,015.81	147,023.24	807,039.05
669X REG ASSET-SWEPCO SHIPE ROAD	816,100.65	-	816,100.65	171,381.14	38,176.37	209,557.51
669Y REG ASSET-2010 SEVERANCE COSTS-LA FI	269,940.70		269,940.70	56,687.55	12,627.56	69,315.11
670O REG ASSET-ENVIRONMENTAL CHEMICAL C	(588,182.20)	-	(588,182.20)	(123,518.26)	(27,514.58)	(151,032.84)
672P REG ASSET-FACILITIES MAINT-SWEPCO LA	(114,086.29)	-	(114,086.29)	(23,958.12)	(5,336.84)	(29,294.96)
673J REG ASSET-WELSH/FLINT CRK ENVIRON DE	958,655.74	209,000.00	1,167,655.74	245,207.71	54,621.77	299,829.48
673K REG ASSET-WELSH/FLINT CRK ENVIRON-C	(335,310.64)	-	(335,310.64)	(70,415.23)	(15,685.50)	(86,100.73)
673U REG ASSET-LA 2015 FRP-SPP DEFERRAL	(375,078.66)	1,316,000.00	940,921.34	197,593.48	44,015.36	241,608.84
673V REG ASSET-LA 2015 FRP-UNREC EQUITY	175,253.45	-	175,253.45	36,803.22	8,198.18	45,001.40
673Z REG ASSET-WELSH 2 TX-UNDEPR BAL	284,097.46	-	284,097.46	59,660.47	13,289.80	72,950.27
Total BOOK DEFERRALS	6,204,546.08	2,260,000.00	8,464,546.08	1,777,554.71	395,963.02	2,173,517.73
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BOOK RESERVES						
651F DISALLOWED COSTS-TURK PLANT	(633,078.53)	(737,000.00)	(1,370,078.53)	(287,716.49)	(64,090.90)	(351,807.39)
651H DISALLOWED COSTS-TURK PLANT AUX BC	(220,150.00)	-	(220,150.00)	(46,231.50)	(10,298.40)	(56,529.90)
651I DISALLOWED COSTS-TX TRANS VEG MGT C	246,212.07	-	246,212.07	51,704.53	11,517.55	63,222.08
651J DISALLOWED COSTS-TX DIST VEG MGT CS	(24,276.23)		(24,276.23)	(5,098.01)	(1,135.62)	(6,233.63)
651K DISALLOWED COSTS-TX TRANS VEG MGT	(13,870.09)	-	(13,870.09)	(2,912.72)	(648.83)	(3,561.55)
651M DISALLOWED COSTS-TX DIST VEG MGT CS	(64,313.61)	-	(64,313.61)	(13,505.86)	(3,008.53)	(16,514.39)
651Q DISALLOWED COSTS-TX SERP COSTS	(351,012.75)	-	(351,012.75)	(73,712.68)	(16,420.03)	(90,132.71)
651R DISALLOWED COSTS-TX DIST COSTS	(183,982.07)	-	(183,982.07)	(38,636.23)	(8,606.50)	(47,242.73)
651S DISALLOWED COSTS-TX GEN COSTS	(5,901,516.59)	(3,910,066.21)	(9,811,582.80)	(2,060,432.39)	(458,976.03)	(2,519,408.42)
651T DISALLOWED COSTS-TX CWIP FINBASED II	1,747,345.47	-	1,747,345.47	366,942.55	81,739.07	448,681.62
651W DISALLOWED COSTS-TX CWIP FINBASED	2,107,031.67	1,628,000.00	3,735,031.67	784,356.65	174,721.05	959,077.70
651X DISALLOWED COSTS-TX CWIP FINBASED II	2,468,125.88	1,517,000.00	3,985,125.88	836,876.43	186,420.20	1,023,296.63
651Y DISALLOWED COSTS-TX RWIP FINBASED II	63,897.38	-	63,897.38	13,418.45	2,989.06	16,407.51

Southwestern Electric Power Company
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Effective State Tax Rate 0.046779

For the Period: Jan 2018 thru Jul 2018 Actual, Aug-De	January - July 2018	Forecasted Aug - December 2018	7 Months Actual Plus 5 Months Forecasted 2018	Federal Tax Effect	(AR, OK, LA, NE) State Tax Effect (4.6779%)	Total Tax Effect (25.6779%)
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651Z DISALLOWED COSTS-TX RWIP FINBASED II	84,668.54	-	84,668.54	17,780.39	3,960.71	21,741.10
653A DISALLOWED COSTS-TX RWIP FINBASED II	94,091.98	-	94,091.98	19,759.32	4,401.53	24,160.85
Total BOOK RESERVES	(580,826.88)	(1,502,066.21)	(2,082,893.09)	(437,407.56)	(97,435.67)	(534,843.23)
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OTHER MISCELLANEOUS						
690F REG ASSET-NBV-ARO-RETIRED PLANTS	4,153.38	-	4,153.38	872.21	194.29	1,066.50
900A LOSS ON REACQUIRED DEBT	328,020.27	107,000.00	435,020.27	91,354.26	20,349.81	111,704.07
900F BK DEFL-GAIN REACQUIRED DEBT	(6,481.69)	-	(6,481.69)	(1,361.15)	(303.21)	(1,664.36)
906A ACCRD SFAS 106 PST RETIRE EXP	(3,379,341.65)	(3,025,000.00)	(6,404,341.65)	(1,344,911.75)	(299,588.70)	(1,644,500.45)
906F ACCRD OPEB COSTS - SFAS 158	1,412,367.46		1,412,367.46	296,597.17	66,069.14	362,666.31
906K ACCRD SFAS 112 PST EMPLOY BEN	707,942.00		707,942.00	148,667.82	33,116.82	181,784.64
906P ACCRD BOOK ARO EXPENSE - SFAS 143	21,170,807.56	-	21,170,807.56	4,445,869.59	990,349.21	5,436,218.80
906Z SFAS 106 - MEDICARE SUBSIDY - (PPACA)-R	311,097.50	-	311,097.50	65,330.48	14,552.83	79,883.31
911S ACCRUED SALES & USE TAX RESERVE	(311,500.00)		(311,500.00)	(65,415.00)	(14,571.66)	(79,986.66)
913D CHARITABLE CONTRIBUTION CARRYFRWD	(4,501,000.00)	-	(4,501,000.00)	(945,210.00)	(210,552.28)	(1,155,762.28)
914A SFAS 109 - DEFD SIT LIABILITY	1,860,387.00	-	1,860,387.00	390,681.27	87,027.04	477,708.31
914B REG ASSET - SFAS 109 DSIT LIAB	(1,860,387.00)	-	(1,860,387.00)	(390,681.27)	(87,027.04)	(477,708.31)
930A BOOK > TAX BASIS-PRTSHP INVEST	(840,000.00)	-	(840,000.00)	(176,400.00)	(39,294.36)	(215,694.36)
940X IRS CAPITALIZATION ADJUSTMENT	(225,012.00)		(225,012.00)	(47,252.52)	(10,525.84)	(57,778.36)
980A RESTRICTED STOCK PLAN	(208,192.70)		(208,192.70)	(43,720.47)	(9,739.05)	(53,459.52)
980J PSI-STOCK-BASED PLAN	191,609.08		191,609.08	40,237.91	8,963.28	49,201.19
999Q DEFD STATE INCOME TAXES	-		-	-	-	-
Total OTHER MISCELLANEOUS	14,654,469.21	(2,918,000.00)	11,736,469.21	2,464,658.55	549,020.28	3,013,678.83
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PERMANENT SCHEDULE M's						
910B NON-DEDUCT MEALS AND T&E	225,188.20	393,000.00	618,188.20	129,819.52	28,918.23	158,737.75
910C NON-DEDUCT FINES&PENALTIES	72,695.76		72,695.76	15,266.11	3,400.63	18,666.74
910S NON-DEDUCT LOBBYING	417,852.91	-	417,852.91	87,749.11	19,546.74	107,295.85
980B RESTRICTED STOCK PLAN-TAX DEDUCTION	(74,558.55)		(74,558.55)	(15,657.30)	(3,487.77)	(19,145.07)
Total PERMANENT SCHEDULE M's	641,178.32	393,000.00	1,034,178.32	217,177.44	48,377.83	265,555.27
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TAX ACCRUALS						
711O BOOK LEASES CAPITALIZED FOR TAX	2,128,000.00	-	2,128,000.00	446,880.00	99,545.71	546,425.71
Total TAX ACCRUALS	2,128,000.00	-	2,128,000.00	446,880.00	99,545.71	546,425.71
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TAX DEFERRALS						
702A GOODWILL PER TAX	(235,522.00)	(168,000.00)	(403,522.00)	(84,739.62)	(18,876.36)	(103,615.98)
710H AMORT ELEC PLT ACQ ADJS	(35,623.00)	-	(35,623.00)	(7,480.83)	(1,666.41)	(9,147.24)
712K CAPITALIZED SOFTWARE COST-BOOK	(2,349,586.71)		(2,349,586.71)	(493,413.21)	(109,911.32)	(603,324.53)
Total TAX DEFERRALS	(2,620,731.71)	(168,000.00)	(2,788,731.71)	(585,633.66)	(130,454.09)	(716,087.75)
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MARK-TO-MARKET ADJUSTMENTS						
575E MTM BK GAIN-A/L-TAX DEFL	3,769,875.00	-	3,769,875.00	791,673.75	176,350.98	968,024.73
610V PROV-FAS 157 - A/L	(15,837.00)	-	(15,837.00)	(3,325.77)	(740.84)	(4,066.61)
652G REG LIAB-UNREAL MTM GAIN-DEFL	(3,754,037.38)	-	(3,754,037.38)	(788,347.85)	(175,610.11)	(963,957.96)
Total MARK-TO-MARKET ADJUSTMENTS	0.62	-	0.62	0.13	0.03	0.16
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EMISSION ALLOWANCES						
638A BOOK > TAX BASIS - EMA-A/C 283	64,078.00	100,000.00	164,078.00	34,456.38	7,675.40	42,131.78
Total EMISSION ALLOWANCES	64,078.00	100,000.00	164,078.00	34,456.38	7,675.40	42,131.78
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Total Book/Tax Income Differences	(10,881,848.47)	(43,832,066.21)	(54,713,914.68)	(11,489,922.06)	(2,559,462.25)	(14,049,384.31)
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Southwestern Electric Power Company
Accumulated Deferred Income Taxes - Total
Test Year Ending December 31, 2018
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WP C-10-2

Effective State Tax Rate 0.046779

For the Period: Jan 2018 thru Jul 2018 Actual, Aug-De	January - July 2018	Forecasted Aug - December 2018	7 Months Actual Plus 5 Months Forecasted 2018	Federal Tax Effect	(AR, OK, LA, NE) State Tax Effect (4.6779%)	Total Tax Effect (25.6779%)
==						
Taxable Income Before State Tax	82,860,481.04	21,517,017.79	104,377,498.83	21,919,274.75	4,882,675.02	26,801,949.77
State and Local Current Tax	2,577,721.18	-	2,577,721.18	541,321.45	(2,304,953.84)	(2,846,275.29)
Federal Taxable Income	80,282,759.86	21,517,017.79	101,799,777.65	21,377,953.30		23,955,674.48
Statutory Rate	21%	21%	21%			
Current Federal Tax Before Credits	16,859,379.57	4,518,573.74	21,377,953.31	21,377,953.30		
Credits	4,366,706.23	608,000.00	4,974,706.23	4,974,706.23		
Reclass from Current to Deferred		(206,115.74)	(206,115.74)	(206,115.74)		
Current Federal Tax	12,492,673.34	3,704,458.00	16,197,131.34	16,403,247.07		

1 Note: Schedule shows the Test Year book income and book/tax temporary differences and the resulting federal and state tax effects on ADIT for Total Company as well as current income tax expense

2 Note: Source of January - July 2018 amounts is PowerPlant Provision Software

3 Note: Source of Forecasted August - December 2018 amounts is Forecast Software

4 Note: The three digit number in column A is the Schedule M indicator from PowerPlant Provision Software

Southwestern Electric Power Company
Accumulated Deferred Income Taxes - Operating
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP C-10-3

Effective State Tax Rate 0.046779

For the Period: Jan 2018 thru Jul 2018 Actual, Aug-Dec Forecasted	Jan - Jul 2018	Forecasted Aug - Dec. 2018	7 Months Actual Plus 5 Months Forecasted 2018	Federal Tax Effect	(AR, OK, LA, NE) State Tax Effect (4.6779%)	Total Tax Effect (25.6779%)
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Book Income	112,577,867.17	62,544,835.00	175,122,702.17	36,775,767.46	8,192,064.88	44,967,832.34
Tax Items	14,725.71		14,725.71			
Book Income Before Tax	112,592,592.88	62,544,835.00	175,137,427.88	36,778,859.85	8,192,753.74	44,971,613.59
==						
EXCESS TAX vs BOOK DEPRECIATION						
230A ACRS BENEFIT NORMALIZED	7,644,000.00	(8,351,000.00)	(707,000.00)	(148,470.00)	(33,072.75)	(181,542.75)
280A EXCESS TX VS S/L BK DEPR	3,780,000.00	2,920,000.00	6,700,000.00	1,407,000.00	313,419.30	1,720,419.30
280H BK PLANT IN SERVICE - SFAS 143 - ARO	(23,154,213.88)	1,011,000.00	(22,143,213.88)	(4,650,074.91)	(1,035,837.40)	(5,685,912.31)
390A CIAC - BOOK RECEIPTS	1,261,037.94	1,123,000.00	2,384,037.94	500,647.97	111,522.91	612,170.88
Total EXCESS TAX vs BOOK DEPRECIATION	(10,469,175.94)	(3,297,000.00)	(13,766,175.94)	(2,890,896.94)	(643,967.94)	(3,534,864.88)
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AFUDC / INTEREST CAPITALIZED						
320A ABFUDC	(3,242,825.59)	(2,979,000.00)	(6,221,825.59)	(1,306,583.37)	(291,050.78)	(1,597,634.15)
380J INT EXP CAPITALIZED FOR TAX	4,849,619.62	2,694,000.00	7,543,619.62	1,584,160.12	352,882.98	1,937,043.10
Total AFUDC / INTEREST CAPITALIZED	1,606,794.03	(285,000.00)	1,321,794.03	277,576.75	61,832.20	339,408.95
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PERCENT REPAIR ALLOWANCE						
532C BOOK/TAX UNIT OF PROPERTY ADJ	(31,549,000.00)	(32,441,000.00)	(63,990,000.00)	(13,437,900.00)	(2,993,388.21)	(16,431,288.21)
532D BOOK/TAX UNIT OF PROPERTY ADJ-SEC 481 ADJ	3,353,000.00	117,000.00	3,470,000.00	728,700.00	162,323.13	891,023.13
534A CAPITALIZED RELOCATION COSTS	(1,988,000.00)	(1,420,000.00)	(3,408,000.00)	(715,680.00)	(159,422.83)	(875,102.83)
Total PERCENT REPAIR ALLOWANCE	(30,184,000.00)	(33,744,000.00)	(63,928,000.00)	(13,424,880.00)	(2,990,487.91)	(16,415,367.91)
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REMOVAL COSTS						
910K REMOVAL CST	(12,401,000.00)	(8,804,000.00)	(21,205,000.00)	(4,453,050.00)	(991,948.70)	(5,444,998.70)
Total REMOVAL COSTS	(12,401,000.00)	(8,804,000.00)	(21,205,000.00)	(4,453,050.00)	(991,948.70)	(5,444,998.70)
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ACCELERATED AMORTIZATION						
533A TX AMORTIZATION POLLUTION CONTROL EQPT	(2,877,000.00)	-	(2,877,000.00)	(604,170.00)	(134,583.18)	(738,753.18)
533J TX ACCEL AMORT-CAPITALIZED SOFTWARE	(483,000.00)		(483,000.00)	(101,430.00)	(22,594.26)	(124,024.26)
Total ACCELERATED AMORTIZATION	(3,360,000.00)	-	(3,360,000.00)	(705,600.00)	(157,177.44)	(862,777.44)
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MINE DEVELOPMENT						
921A BK DEPLETION-MINERALS & RIGHTS	1,006,997.38	(6,399,000.00)	(5,392,002.62)	(1,132,320.55)	(252,232.49)	(1,384,553.04)
921G ACCEL BOOK DEPLETION	(8,400,000.00)	(6,792,000.00)	(15,192,000.00)	(3,190,320.00)	(710,666.57)	(3,900,986.57)
Total MINE DEVELOPMENT	(7,393,002.62)	(13,191,000.00)	(20,584,002.62)	(4,322,640.55)	(962,899.06)	(5,285,539.61)
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REVENUE REFUNDS						
520A PROVS POSS REV REFDS	1,611,191.29		1,611,191.29	338,350.17	75,369.92	413,720.09
520X PROV FOR RATE REFUND-TAX REFORM	29,008,073.17		29,008,073.17	6,091,695.37	1,356,968.65	7,448,664.02
520Y PROV FOR RATE REFUND-EXCESS PROTECTED	8,184,184.92		8,184,184.92	1,718,678.83	382,847.99	2,101,526.82
Total REVENUE REFUNDS	38,803,449.38	-	38,803,449.38	8,148,724.37	1,815,186.56	9,963,910.93
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DEFERRED FUEL COSTS						
433C AR - FUEL OVER/UNDER RECOVERY	(1,966,281.83)	16,349,000.00	14,382,718.17	3,020,370.82	672,809.17	3,693,179.99
433D LA - FUEL OVER/UNDER RECOVERY	(3,227.00)	-	(3,227.00)	(677.67)	(150.96)	(828.63)
Total DEFERRED FUEL COSTS	(1,969,508.83)	16,349,000.00	14,379,491.17	3,019,693.15	672,658.21	3,692,351.36

Southwestern Electric Power Company
Accumulated Deferred Income Taxes - Operating
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP C-10-3

Effective State Tax Rate 0.046779

For the Period: Jan 2018 thru Jul 2018 Actual, Aug-Dec Forecasted	Jan - Jul 2018	Forecasted Aug - Dec. 2018	7 Months Actual Plus 5 Months Forecasted 2018	Federal Tax Effect	(AR, OK, LA, NE) State Tax Effect (4.6779%)	Total Tax Effect (25.6779%)
==						
BOOK ACCRUALS						
602A PROV WORKER'S COMP	303,756.72		303,756.72	63,788.91	14,209.44	77,998.35
605B ACCRUED BK PENSION EXPENSE	3,941,213.58	2,169,000.00	6,110,213.58	1,283,144.85	285,829.68	1,568,974.53
605C ACCRUED BK PENSION COSTS - SFAS 158	(2,505,367.50)		(2,505,367.50)	(526,127.18)	(117,198.59)	(643,325.77)
605E SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN	50,236.68		50,236.68	10,549.70	2,350.02	12,899.72
605F ACCRD SUP EXEC RETIR PLAN COSTS-SFAS 158	(28,785.50)		(28,785.50)	(6,044.96)	(1,346.56)	(7,391.52)
605I ACCRD BK SUP. SAVINGS PLAN EXP	(99,160.73)		(99,160.73)	(20,823.75)	(4,638.64)	(25,462.39)
605K ACCRUED BK BENEFIT COSTS	(12,972.41)		(12,972.41)	(2,724.21)	(606.84)	(3,331.05)
605O ACCRUED PSI PLAN EXP	(2,200,062.36)		(2,200,062.36)	(462,013.10)	(102,916.72)	(564,929.82)
610A BK PROV UNCOLL ACCTS	(771,733.19)		(771,733.19)	(162,063.97)	(36,100.91)	(198,164.88)
611E ACCRUED MINE RECLAMATION	730,553.83		730,553.83	153,416.30	34,174.58	187,590.88
612Y ACCRD COMPANYWIDE INCENTV PLAN	(1,511,902.00)	2,736,000.00	1,224,098.00	257,060.58	57,262.08	314,322.66
613E ACCRUED BOOK VACATION PAY	791,254.18		791,254.18	166,163.38	37,014.08	203,177.46
613K (ICDP)-INCENTIVE COMP DEFERRAL PLAN	23,454.61	-	23,454.61	4,925.47	1,097.18	6,022.65
615B ACCRUED INTEREST-LONG-TERM - FIN 48	107,036.00	-	107,036.00	22,477.56	5,007.04	27,484.60
615C ACCRUED INTEREST-SHORT-TERM - FIN 48	4,798.00		4,798.00	1,007.58	224.45	1,232.03
Total BOOK ACCRUALS	(1,177,680.09)	4,905,000.00	3,727,319.91	782,737.16	174,360.29	957,097.45
==						
BOOK DEFERRALS						
615O BK DFL RAIL TRANS REV/EXP	(141.35)		(141.35)	(29.68)	(6.61)	(36.29)
630M RATE CASE DEFD CHGS	1,664,837.77		1,664,837.77	349,615.93	77,879.45	427,495.38
641I ADVANCE RENTAL INC (CUR MO)	1,131,640.20	(625,000.00)	506,640.20	106,394.44	23,700.12	130,094.56
660F REG ASSET - SFAS 143 - ARO	(779,208.67)		(779,208.67)	(163,633.82)	(36,450.60)	(200,084.42)
661R REG ASSET - SFAS 158 - PENSIONS	2,505,367.50		2,505,367.50	526,127.18	117,198.59	643,325.77
661S REG ASSET - SFAS 158 - SERP	28,785.50		28,785.50	6,044.96	1,346.56	7,391.52
661T REG ASSET - SFAS 158 - OPEB	(1,412,367.46)		(1,412,367.46)	(296,597.17)	(66,069.14)	(362,666.31)
664A REG ASSET-UND/REC ENVIRON ADJ CLAUSE-LA	80,107.60		80,107.60	16,822.60	3,747.35	20,569.95
664R REG ASSET-VALLEY DISTRICT DUE DILIGENCE	33,032.03		33,032.03	6,936.73	1,545.21	8,481.94
664V REG ASSET-NET CCS FEED STUDY COSTS	23,215.80		23,215.80	4,875.32	1,086.01	5,961.33
668P REG ASSET-LA FRP ASSET	54,954.54		54,954.54	11,540.45	2,570.72	14,111.17
669J REG ASSET-ENERGY EFFICIENCY RECOVERY	1,782,932.41	1,360,000.00	3,142,932.41	660,015.81	147,023.24	807,039.05
669X REG ASSET-SWEPCO SHIPE ROAD	816,100.65		816,100.65	171,381.14	38,176.37	209,557.51
669Y REG ASSET-2010 SEVERANCE COSTS-LA FRP	269,940.70		269,940.70	56,687.55	12,627.56	69,315.11
670O REG ASSET-ENVIRONMENTAL CHEMICAL COST-AR	(588,182.20)		(588,182.20)	(123,518.26)	(27,514.58)	(151,032.84)
672P REG ASSET-FACILITIES MAINT-SWEPCO LA	(114,086.29)		(114,086.29)	(23,958.12)	(5,336.84)	(29,294.96)
673J REG ASSET-WELSH/FLINT CRK ENVIRON DEF	958,655.74	209,000.00	1,167,655.74	245,207.71	54,621.77	299,829.48
673K REG ASSET-WELSH/FLINT CRK ENVIRON-CONTRA	(335,310.64)		(335,310.64)	(70,415.23)	(15,685.50)	(86,100.73)
673U REG ASSET-LA 2015 FRP-SPP DEFERRAL	(375,078.66)	1,316,000.00	940,921.34	197,593.48	44,015.36	241,608.84
673V REG ASSET-LA 2015 FRP-UNREC EQUITY	175,253.45		175,253.45	36,803.22	8,198.18	45,001.40
673Z REG ASSET-WELSH 2 TX-UNDEPR BAL	284,097.46		284,097.46	59,660.47	13,289.80	72,950.27
Total BOOK DEFERRALS	6,204,546.08	2,260,000.00	8,464,546.08	1,777,584.39	395,969.63	2,173,554.02
==						
BOOK RESERVES						
651F DISALLOWED COSTS-TURK PLANT	(633,078.53)	(737,000.00)	(1,370,078.53)	(287,716.49)	(64,090.90)	(351,807.39)
651H DISALLOWED COSTS-TURK PLANT AUX BOILER	(220,150.00)		(220,150.00)	(46,231.50)	(10,298.40)	(56,529.90)

Southwestern Electric Power Company **WP C-10-3**
Accumulated Deferred Income Taxes - Operating
Test Year Ending December 31, 2018 Effective State Tax Rate 0.046779
Docket No. 19-008-U

For the Period: Jan 2018 thru Jul 2018 Actual, Aug-Dec Forecasted	Jan - Jul 2018	Forecasted Aug - Dec. 2018	7 Months Actual Plus 5 Months Forecasted 2018	Federal Tax Effect	(AR, OK, LA, NE) State Tax Effect (4.6779%)	Total Tax Effect (25.6779%)
651I DISALLOWED COSTS-TX TRANS VEG MGT CST	246,212.07		246,212.07	51,704.53	11,517.55	63,222.08
651J DISALLOWED COSTS-TX DIST VEG MGT CST	(24,276.23)		(24,276.23)	(5,098.01)	(1,135.62)	(6,233.63)
651K DISALLOWED COSTS-TX TRANS VEG MGT CST-AMORT	(13,870.09)		(13,870.09)	(2,912.72)	(648.83)	(3,561.55)
651M DISALLOWED COSTS-TX DIST VEG MGT CST-AMORT	(64,313.61)		(64,313.61)	(13,505.86)	(3,008.53)	(16,514.39)
651Q DISALLOWED COSTS-TX SERP COSTS	(351,012.75)		(351,012.75)	(73,712.68)	(16,420.03)	(90,132.71)
651R DISALLOWED COSTS-TX DIST COSTS	(183,982.07)		(183,982.07)	(38,636.23)	(8,606.50)	(47,242.73)
651S DISALLOWED COSTS-TX GEN COSTS	(5,901,516.59)	(7,374,096.91)	(13,275,613.50)	(2,787,878.84)	(621,019.92)	(3,408,898.76)
651T DISALLOWED COSTS-TX CWIP FINBASED INCEN-TRANS	1,747,345.47		1,747,345.47	366,942.55	81,739.07	448,681.62
651W DISALLOWED COSTS-TX CWIP FINBASED INCEN-DIST	2,107,031.67	1,628,000.00	3,735,031.67	784,356.65	174,721.05	959,077.70
651X DISALLOWED COSTS-TX CWIP FINBASED INCEN-GEN	2,468,125.88	1,517,000.00	3,985,125.88	836,876.43	186,420.20	1,023,296.63
651Y DISALLOWED COSTS-TX RWIP FINBASED INCEN-TRANS	63,897.38		63,897.38	13,418.45	2,989.06	16,407.51
651Z DISALLOWED COSTS-TX RWIP FINBASED INCEN-DIST	84,668.54		84,668.54	17,780.39	3,960.71	21,741.10
653A DISALLOWED COSTS-TX RWIP FINBASED INCEN-GEN	94,091.98		94,091.98	19,759.32	4,401.53	24,160.85
Total BOOK RESERVES	(580,826.88)	(4,966,096.91)	(5,546,923.79)	(1,164,854.01)	(259,479.56)	(1,424,333.57)
==						
OTHER MISCELLANEOUS						
690F REG ASSET-NBV-ARO-RETIRED PLANTS	4,153.38		4,153.38	872.21	194.29	1,066.50
900A LOSS ON REACQUIRED DEBT	328,020.27	107,000.00	435,020.27	91,354.26	20,349.81	111,704.07
900F BK DEFL-GAIN REACQUIRED DEBT	(6,481.69)		(6,481.69)	(1,361.15)	(303.21)	(1,664.36)
906A ACCRD SFAS 106 PST RETIRE EXP	(3,379,341.65)	(3,025,000.00)	(6,404,341.65)	(1,344,911.75)	(299,588.70)	(1,644,500.45)
906F ACCRD OPEB COSTS - SFAS 158	1,412,367.46		1,412,367.46	296,597.17	66,069.14	362,666.31
906K ACCRD SFAS 112 PST EMPLOY BEN	707,942.00		707,942.00	148,667.82	33,116.82	181,784.64
906P ACCRD BOOK ARO EXPENSE - SFAS 143	21,170,807.56	-	21,170,807.56	4,445,869.59	990,349.21	5,436,218.80
906Z SFAS 106 - MEDICARE SUBSIDY - (PPACA)-REG ASSET	311,097.50		311,097.50	65,330.48	14,552.83	79,883.31
911S ACCRUED SALES & USE TAX RESERVE	(311,500.00)		(311,500.00)	(65,415.00)	(14,571.66)	(79,986.66)
914A SFAS 109 - DEFD SIT LIABILITY	1,860,387.00		1,860,387.00	390,681.27	87,027.04	477,708.31
914B REG ASSET - SFAS 109 DSIT LIAB	(1,860,387.00)		(1,860,387.00)	(390,681.27)	(87,027.04)	(477,708.31)
930A BOOK > TAX BASIS-PRTSHP INVEST	(840,000.00)		(840,000.00)	(176,400.00)	(39,294.36)	(215,694.36)
940X IRS CAPITALIZATION ADJUSTMENT	(225,012.00)		(225,012.00)	(47,252.52)	(10,525.84)	(57,778.36)
980A RESTRICTED STOCK PLAN	(208,192.70)		(208,192.70)	(43,720.47)	(9,739.05)	(53,459.52)
980J PSI-STOCK-BASED PLAN	191,609.08		191,609.08	40,237.91	8,963.28	49,201.19
Total OTHER MISCELLANEOUS	19,155,469.21	(2,918,000.00)	16,237,469.21	3,409,868.55	759,572.56	4,169,441.11
==						
PERMANENT SCHEDULE M's						
910B NON-DEDUCT MEALS AND T&E	225,188.20	393,000.00	618,188.20	129,819.52	28,918.23	158,737.75
910E NON-DEDUCT - MISCELLANEOUS	(120,028.87)		(120,028.87)	(25,206.06)	(5,614.83)	(30,820.89)
980B RESTRICTED STOCK PLAN-TAX DEDUCTION	(74,558.55)		(74,558.55)	(15,657.30)	(3,487.77)	(19,145.07)
Total PERMANENT SCHEDULE M's	30,600.78	393,000.00	423,600.78	88,956.16	19,815.63	108,771.79
==						
TAX ACCRUALS						
711O BOOK LEASES CAPITALIZED FOR TAX	2,128,000.00		2,128,000.00	446,880.00	99,545.71	546,425.71
Total TAX ACCRUALS	2,128,000.00	-	2,128,000.00	446,880.00	99,545.71	546,425.71
==						
TAX DEFERRALS						
702A GOODWILL PER TAX	(235,522.00)	(168,000.00)	(403,522.00)	(84,739.62)	(18,876.36)	(103,615.98)
710H AMORT ELEC PLT ACQ ADJS	(35,623.00)	-	(35,623.00)	(7,480.83)	(1,666.41)	(9,147.24)

Southwestern Electric Power Company
Accumulated Deferred Income Taxes - Operating
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP C-10-3

Effective State Tax Rate 0.046779

For the Period: Jan 2018 thru Jul 2018 Actual, Aug-Dec Forecasted	**Jan - Jul 2018**	**Forecasted Aug - Dec. 2018**	**7 Months Actual Plus 5 Months Forecasted 2018**	**Federal Tax Effect**	**(AR, OK, LA, NE) State Tax Effect (4.6779%)**	**Total Tax Effect (25.6779%)**
712K CAPITALIZED SOFTWARE COST-BOOK	(2,349,586.71)		(2,349,586.71)	(493,413.21)	(109,911.32)	(603,324.53)
Total TAX DEFERRALS	(2,620,731.71)	(168,000.00)	(2,788,731.71)	(585,633.66)	(130,454.09)	(716,087.75)
==						
MARK-TO-MARKET ADJUSTMENTS						
575E MTM BK GAIN-A/L-TAX DEFL	3,769,875.00		3,769,875.00	791,673.75	176,350.98	968,024.73
610V PROV-FAS 157 - A/L	(15,837.00)		(15,837.00)	(3,325.77)	(740.84)	(4,066.61)
652G REG LIAB-UNREAL MTM GAIN-DEFL	(3,754,037.38)		(3,754,037.38)	(788,347.85)	(175,610.11)	(963,957.96)
Total MARK-TO-MARKET ADJUSTMENTS	0.62	-	0.62	0.13	0.03	0.16
==						
EMISSION ALLOWANCES						
638A BOOK > TAX BASIS - EMA-A/C 283	64,078.00	100,000.00	164,078.00	34,456.38	7,675.40	42,131.78
Total EMISSION ALLOWANCES	64,078.00	100,000.00	164,078.00	34,456.38	7,675.40	42,131.78
==						
Total Book/Tax Income Differences	(2,162,987.97)	(43,366,096.91)	(45,529,084.88)	(9,561,078.12)	(2,129,798.48)	(11,690,876.60)
==						
Taxable Income Before State Tax	110,429,604.91	19,178,738.09	129,608,343.00	27,217,752.03	6,062,948.68	33,280,700.71
State and Local Current Tax	3,840,773.51	-	3,840,773.51	806,562.44	(2,222,175.17)	(3,028,737.61)
Federal Taxable Income	106,588,831.40	19,178,738.09	125,767,569.49	26,411,189.59		30,251,963.10
Statutory Rate	21%	21%	21%			
Current Federal Tax Before Credits	22,383,654.59	4,027,535.00	26,411,189.59	26,411,189.59		
Credits	3,542,824.41	(44,818.00)	3,498,006.41	3,498,006.41		
Current Federal Tax	18,840,830.18	4,072,353.00	22,913,183.18	22,913,183.18		

1 Note: Schedule shows the federal and state tax effects (current and deferred) of book/tax temporary differences and permanent differences for Test Year Operating Income

2 Note: Removed 913D, 330D & Equity in Subs because it's nonoperating

3 Note: Source of January - July 2018 amounts is PowerPlant Provision Software

4 Note: Source of Forecasted August - December 2018 amounts is Forecast Software

5 Note: The three digit number in column A is the Schedule M indicator from PowerPlant Provision Software

Southwestern Electric Power Company
Accumulated Deferred Income Taxes- Account 190
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP C-10-4

DEBIT (CREDIT)

Line No.	COLUMN A ACCUMULATED DEFERRED FIT ITEMS	COLUMN B PER BOOKS BALANCE AS OF 7-31-18	COLUMN C PER BOOKS ACTIVITY AUG-DEC 2018	COLUMN D PER BOOKS PROJECTED BALANCE AS OF 12-31-18 (A)	COLUMN E NON-APPLICABLE/ NON-UTILITY BALANCE AS OF 12-31-18	COLUMN F PROJECTED UTILITY BALANCE AS OF 12-31-18	COLUMN G ADJUSTMENTS	COLUMN H(A) JAN - DEC 2019 TOTAL COMPANY
	ACCOUNT 190:							
1	AR - FUEL OVER/UNDER RECOVERY	(3,366,715)		(3,366,715)		(3,366,715) (c)	3,366,715	0
2	LA - FUEL OVER/UNDER RECOVERY	(678)		(678)		(678) (c)	678	0
3	UNBILLED REVENUE	4,646,289		4,646,289		4,646,289 (c)	(4,646,289)	0
4	PROVS POSS REV REFDS	2,921,674.48		2,921,674		2,921,674 (c)	(2,921,674)	0
5	PROV FOR RATE REFUND-TAX REFORM	6,091,695.36		6,091,695		6,091,695 (c)	(6,091,695)	0
6	PROV FOR RATE REFUND-EXCESS PROTECTED	1,718,678.83		1,718,679		1,718,679 (c)	(1,718,679)	0
7	MARK & SPREAD-DEFL-190-A/L	(37,376)		(37,376)		(37,376) (c)	37,376	0
8	PROV WORKER'S COMP	162,300		162,300		162,300		162,300
9	SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN	235,258		235,258		235,258		235,258
10	ACCRD SUP EXEC RETIRE PLAN COSTS SFAS 158	231,251		231,251		231,251 (c)	(231,251)	0
11	ACCRD BK SUP. SAVINGS PLAN EXP	222,486		222,486		222,486		222,486
12	ACCRUED BK BENEFIT COSTS	15,886		15,886		15,886		15,886
13	ACCRUED PSI PLAN EXP	239,512		239,512		239,512		239,512
14	STOCK BASED COMP-CAREER SHARES	673,767		673,767		673,767		673,767
15	BK PROV UNCOLL ACCTS	117,120		117,120		117,120		117,120
16	PROV-TRADING CREDIT RISK - A/L	35		35		35 (c)	(35)	0
17	PROV-FAS 157 - A/L	(3,683)		(3,683)		(3,683) (c)	3,683	0
18	ACCRUED MINE RECLAMATION	7,261,014		7,261,014		7,261,014 (c)	(7,261,014)	0
19	DEFD COMPENSATION-BOOK EXPENSE	355,965		355,965		355,965		355,965
20	ACCRD COMPANYWIDE INCENTV PLAN	1,574,508		1,574,508		1,574,508		1,574,508
21	ACCRD ENVIRONMENTAL LIAB	5,489		5,489		5,489		5,489
22	ACCRUED BOOK VACATION PAY	2,397,680		2,397,680		2,397,680		2,397,680
23	ACCRD ENVIRONMENTAL LIAB	716		716		716		716
24	ICDP - INCENTIVE COMP DEFERRAL PLAN	26,543		26,543		26,543		26,543
25	ACCRUED INTEREST EXP -STATE	(372,842)		(372,842)		(372,842) (c)	372,842	0
26	ACCRUE INTEREST-TAX RES-L/T-FIN 48	22,643		22,643		22,643 (c)	(22,643)	0
27	ACCRUED INTEREST S/T FIN 48	4,365		4,365		4,365 (c)	(4,365)	0
28	BK DFL RAIL TRANS REV/EXP	(30)		(30)		(30) (c)	30	0
29	ADVANCE RENTAL INC (CUR MO)	458,398		458,398		458,398		458,398
30	DEFERRED INCOME - DOLET HILLS MINING BUYOUT	57,310		57,310		57,310 (c)	(57,310)	0
31	DISALLOWED COSTS-TURK PLANT	11,103,564.73		11,103,565		11,103,565 (c)	(11,103,565)	0
32	DISALLOWED COSTS-TURK PLANT AUX BOILER	3,469,022.35		3,469,022		3,469,022 (c)	(3,469,022)	0
33	DISALLOWED COSTS-TX TRANS VEG MGT CST	302,621.36		302,621		302,621 (c)	(302,621)	0
34	DISALLOWED COSTS-TX DIST VEG MGT CST	861,751.19		861,751		861,751 (c)	(861,751)	0
35	DISALLOWED COSTS-TX TRANS VEG MGT CST-AMORT	(12,733.60)		(12,734)		(12,734) (c)	12,734	0
36	DISALLOWED COSTS-TX DIST VEG MGT CST-AMORT	(65,180.25)		(65,180)		(65,180) (c)	65,180	0
37	DISALLOWED COSTS-TX SERP COSTS	33,499.90		33,500		33,500 (c)	(33,500)	0
38	DISALLOWED COSTS-TX DIST COSTS	10,040.46		10,040		10,040 (c)	(10,040)	0

Southwestern Electric Power Company
Accumulated Deferred Income Taxes- Account 190
Test Year Ending December 31, 2018
Docket No. 19-008-U

DEBIT (CREDIT)

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F		COLUMN G	COLUMN H(A)
		PER BOOKS			NON-APPLICABLE/ NON-UTILITY	PROJECTED UTILITY			
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS OF 7-31-18	ACTIVITY AUG-DEC 2018	PROJECTED BALANCE AS OF 12-31-18 (A)	BALANCE AS OF 12-31-18	BALANCE AS OF 12-31-18		ADJUSTMENTS	JAN - DEC 2019 TOTAL COMPANY
39	DISALLOWED COSTS-TX CWIP FINBASED INCEN-TRANS	366,942.55		366,943		366,943	(c)	(366,943)	0
40	DISALLOWED COSTS-TX CWIP FINBASED INCEN-DIST	442,476.65		442,477		442,477	(c)	(442,477)	0
41	DISALLOWED COSTS-TX CWIP FINBASED INCEN-GEN	518,306.43		518,306		518,306	(c)	(518,306)	0
42	DISALLOWED COSTS-TX RWIP FINBASED INCEN-TRANS	13,418.45		13,418		13,418	(c)	(13,418)	0
43	DISALLOWED COSTS-TX RWIP FINBASED INCEN-DIST	17,780.39		17,780		17,780	(c)	(17,780)	0
44	REG LIAB-UNREAL MTM GAIN-DEFL	(249,196)		(249,196)		(249,196)	(c)	249,196	0
45	DISALLOWED COSTS-TX RWIP FINBASED INCEN-GEN	19,759.32		19,759		19,759	(c)	(19,759)	0
46	AMORT - GOODWILL PER BOOKS	1,271,788.98		1,271,789		1,271,789	(c)	(1,271,789)	0
47	GOODWILL PER TAX	(664,158.39)		(664,158)		(664,158)	(c)	664,158	0
48	AMORT ELEC PLT ACQ ADJS	91,902.72		91,903		91,903			91,903
49	ACCRUED OPEB COSTS - SFAS 158	(491,605.55)		(491,606)		(491,606)	(c)	491,606	0
50	ACCRD BOOK ARO EXPENSE - SFAS 143	23,925,097.20		23,925,097		23,925,097			23,925,097
51	FIN 48 DSIT	(20,804.70)		(20,805)		(20,805)	(c)	20,805	0
52	ACCRUED SIT TX RES L/T FIN48	(159,964.35)		(159,964)		(159,964)	(c)	159,964	0
53	ACCRD SIT TX RESERVE-SHRT-TERM-FIN 48	11,265.66		11,266		11,266	(c)	(11,266)	0
54	IRS AUDIT SETTLEMENT	(1,356,243.21)		(1,356,243)		(1,356,243)			(1,356,243)
55	IRS CAPITALIZATION ADJUSTMENT	363,635.28		363,635		363,635			363,635
56	AMT CREDIT - DEFERRED	(0.14)		0		0			0
57	RESTRICTED STOCK PLAN	20,796.82		20,797		20,797			20,797
58	PSI - STOCK BASED COMP	107,185.74		107,186		107,186			107,186
59	CHARITABLE CONTRIBUTION CARRYFORWARD	673,974.81		673,975		673,975	(c)	(673,975)	0
60	SFAS 109 FLOW-THRU 190.3	41,633,476		41,633,476	0	41,633,476			41,633,476
61	SFAS 109 EXCESS DFIT 190.4	148,407,966		148,407,966		148,407,966	(b)	(42,511,572)	105,896,394
62	ADIT FED - PENSION OCI NAF 1900011	(417,286)		(417,286)		(417,286)	(c)	417,286	0
63	ADIT FED - HEDGE-INTEREST RATE 1900015	1,626,300		1,626,300		1,626,300	(c)	(1,626,300)	0
64	DEFERRED SIT 1901002	47,097,817		47,097,817		47,097,817	(c)	(47,097,817)	0
65									
66	TOTAL ACCOUNT 190 (a)	304,612,478	0	304,612,478	0	304,612,478		(127,444,603)	177,167,873

(a) E-17B Trial Balance
(b) Turk adjustment - See WP B 2-5-2
(c) Adjustments are nonapplicable for a base Filing

1Note: Purpose: Provides detail of Test Year and Pro forma Acct 190

2 Note: Source of January - July 2018 amounts is PowerPlant Provision Software

3 Note: Source of Forecasted August - December 2018 amounts is Forecast Software

Recap Schedules:
(A) WP C-10-1

Supporting Schedules:
Schedule E-17B
WP B 2-7.2 Turk

Southwestern Electric Power Company
Accumulated Deferred Income Taxes- Accounts 281-283
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP C-10-5

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F		COLUMN G	COLUMN H
		PER BOOKS			NON-APPLICABLE/ NON-UTILITY	PROJECTED UTILITY			JAN - DEC 2018 TOTAL COMPANY
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS OF 7-31-18	ACTIVITY JUL-DEC 2018	PROJECTED BALANCE AS OF 12-31-18 (A)	BALANCE AS OF 12-31-18	BALANCE AS OF 12-31-18		ADJUSTMENTS	ADJUSTED @ 12/19
	ACCOUNT 281:								
533A	TX AMORT POLLUTION CONT EQPT	40,875,259.95		40,875,260		40,875,260	(c)	(40,875,260)	0
960F-XS	EXCESS ADFIT 281 - PROTECTED	26,962,712		26,962,712		26,962,712	(d)	(1,968,406)	24,994,306
	Deferred 281 Adjustment		478,246	478,246		478,246			478,246
	SFAS 109 EXCESS DFIT 281.4	(26,962,712)	(190,082)	(27,152,794)		(27,152,794)	(d)	(782,358)	(27,935,152)
	TOTAL ACCOUNT 281	40,875,260	288,164	41,163,424	0	41,163,424		(43,626,024)	(2,462,600)
	Schedule E17-B	40,875,260							
	ACCOUNT 282:								
230A	ACRS BENEFIT NORMALIZED	660,117,816.41	1,753,710	661,871,526		661,871,526	(e)	(28,270,238)	633,601,288
230I	CAPD INTEREST-SECTION 481(a)-CHANGE IN METHD	763,036.47		763,036		763,036			763,036
230J	RELOCATION CST-SECTION 481(a)-CHANGE IN METHD	(48,938.61)		(48,939)		(48,939)			(48,939)
234Q	MACRS TAX DEPRECIATION - RAIL CARS	2,775,164.28		2,775,164		2,775,164			2,775,164
260A	SPARE PARTS INVENTORY	(1,679,950.20)		(1,679,950)		(1,679,950)			(1,679,950)
280H	BK PLANT IN SERVICE - SFAS 143 - ARO	18,552,498.87	(212,310)	18,340,189		18,340,189			18,340,189
295A	GAIN/LOSS ON ACRS/MACRS PROPERTY	23,674,004		23,674,004		23,674,004			23,674,004
320A	ABFUDC	48,273,588	625,590	48,899,178		48,899,178	(f)	(77,881)	48,821,297
380J	INT EXP CAPITALIZED FOR TAX	(76,104,055)	(565,740)	(76,669,795)		(76,669,795)			(76,669,795)
390A	CIAC - BOOK RECEIPTS	(9,632,160)	(235,830)	(9,867,990)		(9,867,990)			(9,867,990)
510H	PROPERTY TAX-NEW METHOD-BOOK	235,401.60		235,402		235,402			235,402
532A	PERCENT REPAIR ALLOWANCE	9,076,043.82		9,076,044		9,076,044			9,076,044
532C	BOOK/TAX UNIT OF PROPERTY ADJ	51,584,887.41	6,812,610	58,397,497		58,397,497			58,397,497
532D	BK/TX UNIT OF PROPERTY ADJ-SEC 481 ADJ	21,257,991.93	(24,570)	21,233,422		21,233,422			21,233,422
533J	TX ACCEL AMORT - CAPITALIZED SOFTWARE	1,516,987.50		1,516,988		1,516,988			1,516,988
534A	CAPITALIZED RELOCATION COSTS	7,803,638	298,200	8,101,838		8,101,838			8,101,838
662A	WRITE-OFF RE SFAS 71	8,435,342		8,435,342		8,435,342			8,435,342
680A	JOINT VENTURES-SYS FUEL PRJ-TX	13,720		13,720		13,720			13,720
710W	BREM & HAUGH ACQUSITION ADJ-TX	(3,730,949)		(3,730,949)		(3,730,949)			(3,730,949)
711N	CAPITAL SOFTWARE COST - TAX	(4,890)		(4,890)		(4,890)			(4,890)
711O	BOOK LEASES CAPITALIZED FOR TAX	(80,710)		(80,710)		(80,710)			(80,710)
712K	CAPITALIZED SOFTWARE COST-BOOK	7,438,912		7,438,912		7,438,912	(g)	1,592,714	9,031,626
910J	INTEREST EXPENSE - COAL CARS	8,507,705		8,507,705		8,507,705			8,507,705
910K	REMOVAL CST	44,850,784	1,848,840	46,699,624		46,699,624			46,699,624
910W	REMOVAL COSTS REV-SFAS 143-ARO	6,338		6,338		6,338			6,338
230X	R & D DEDUCTION - SEC 174	8,479,963		8,479,963		8,479,963			8,479,963

Southwestern Electric Power Company
Accumulated Deferred Income Taxes- Accounts 281-283
Test Year Ending December 31, 2018
Docket No. 19-008-U

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F	COLUMN G	COLUMN H
		PER BOOKS			NON-APPLICABLE/ NON-UTILITY	PROJECTED		
				PROJECTED		UTILITY		JAN - DEC 2018
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS OF 7-31-18	ACTIVITY JUL-DEC 2018	BALANCE AS OF 12-31-18 (A)	BALANCE AS OF 12-31-18	BALANCE AS OF 12-31-18	ADJUSTMENTS	TOTAL COMPANY ADJUSTED @ 12/19
	Deferred 282 Adjustment	0	(625,986)	(625,986)		(625,986)		(625,986)
	EXCESS ADFIT 282 - PROTECTED	507,817,491		507,817,491		507,817,491 (d)	(10,569,468)	497,248,023
	EXCESS ADFIT 282- UNPROTECTED	32,405,417		32,405,417		32,405,417 (d)	(17,257,180)	15,148,237
	SFAS 109 FLOW-THRU 282.3	55,054,998	388,128	55,443,126		55,443,126 (b)	(30,251,385)	25,191,741
	SFAS 109 EXCESS DFIT 282.4	(540,222,908)	(3,808,478)	(544,031,386)	0	(544,031,386)	0	(544,031,386)
	AFUDC Jurisdictional							0
	TURK PLANT ADJUSTMENT	0		(245,585,392)		(245,585,392) (b)	3,047,550	(242,537,842)
	TOTAL ACCOUNT 282	(887,137,168	6,254,164	647,805,939	0	647,805,939	(81,785,888)	566,020,051
	Schedule E17-B	887,137,168						
	ACCOUNT 2831:							
014C	NOL-STATE C/F-DEF TAX ASSET-L/T AR	1,081,726		1,081,726		1,081,726		1,081,726
014C	NOL-STATE C/F-DEF TAX ASSET-L/T LA & OK	8,808,816		8,808,816		8,808,816 (c)	(8,808,816)	0
575E	MTM BK GAIN-A/L-TAX DEFL	(256,207)		(256,207)		(256,207) (c)	256,207	0
576E	MARK & SPREAD DEFL 283 A/L	(28,097)		(28,097)		(28,097) (c)	28,097	0
605B	ACCRUED BK PENSION EXPENSE	17,389,801	(455,490)	16,934,311		16,934,311		16,934,311
605C	ACCRUED BK PENSION COSTS SFAS 158	(19,694,959)		(19,694,959)		(19,694,959) (c)	19,694,959	0
630J	DEFD STORM DAMAGE	(4)		(4)		(4) (c)	4	0
630M	RATE CASE DEFD CHGS	1,144,511		1,144,511		1,144,511 (c)	(1,144,511)	0
632U	BK DEFL-DEMAND SIDE MNGMT EXP	(0)		0		0 (c)	0	0
638A	BOOK > TAX BASIS - EMA-A/C 283	4,982	(21,000)	(16,018)		(16,018) (c)	16,018	0
660F	REG ASSET -SFAS 143 - ARO	1,106,406		1,106,406		1,106,406		1,106,406
661R	REG ASSET - SFAS 158 PENSION	19,694,959		19,694,959		19,694,959 (c)	(19,694,959)	0
661S	REG ASSET - SFAS 158 SERP	231,251		231,251		231,251 (c)	(231,251.00)	0
661T	REG ASSET - SFAS 158 OPEB	(491,606)		(491,606)		(491,606) (c)	491,606.00	0
664A	REG ASSET-UND/REC ENVIRON ADJ CLAUSE-LA	35,046		35,046		35,046 (c)	(35,046.00)	0
664V	REG ASSET-NET CCS FEED STUDY COSTS	93,840		93,840		93,840		93,840
669J	REG ASSET-ENERGY EFFICIENCY RECOVERY	484,392	(285,600)	198,792		198,792		198,792
669X	REG ASSET-SWEPCO SHIPE ROAD	514,143		514,143		514,143		514,143
670O	REG ASSET-ENVIRONMENTAL CHEMICAL COST-AR	569,301		569,301		569,301		569,301
672P	REG ASSET-FACILITIES MAINT-SWEPCO LA	139,796		139,796		139,796 (c)	(139,796)	0
673J	REG ASSET-WELSH/FLINT CRK ENVIRON DEF	4,745,346	(43,890)	4,701,456		4,701,456 (c)	(4,701,456)	0
673K	REG ASSET-WELSH/FLINT CRK ENVIRON-CONTRA	(1,659,788)		(1,659,788)		(1,659,788) (c)	1,659,788	0
673U	REG ASSET-LA 2015 FRP-SPP DEFERRAL	1,069,998	(276,360)	793,638		793,638 (c)	(793,638)	0
673V	REG ASSET-LA 2015 FRP-UNREC EQUITY	(58,405)		(58,405)		(58,405) (c)	58,405	0
673Z	REG ASSET-WELSH 2 TX-UNDEPR BAL	3,631,448		3,631,448		3,631,448 (c)	(3,631,448)	0
690F	REG ASSET-NBV-ARO-RETIRED PLANTS	105,848		105,848		105,848		105,848
900A	LOSS ON REACQUIRED DEBT	909,848	(22,470)	887,378		887,378		887,378
900F	BK DEFL-GAIN REACQUIRED DEBT	(2,842)		(2,842)		(2,842)		(2,842)
906A	ACCRD SFAS 106 PST RETIRE EXP	5,808,028	635,250	6,443,278		6,443,278		6,443,278
906Z	SFAS 106 PST RETIREMENT EXP - NON-DEDUCT CONT	(3,441,111)		(3,441,111)		(3,441,111)		(3,441,111)
906K	ACCRD SFAS 112 PST EMPLOY BEN	(1,184,826)		(1,184,826)		(1,184,826)		(1,184,826)
906Z	SFAS 106 - MEDICARE SUBSIDY - (PPACA)-REG ASSET	718,635		718,635		718,635		718,635

Southwestern Electric Power Company **WP C-10-5**
Accumulated Deferred Income Taxes- Accounts 281-283
Test Year Ending December 31, 2018
Docket No. 19-008-U

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F		COLUMN G	COLUMN H
		PER BOOKS			NON-APPLICABLE/ NON-UTILITY	PROJECTED UTILITY			
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS OF 7-31-18	ACTIVITY JUL-DEC 2018	PROJECTED BALANCE AS OF 12-31-18 (A)	BALANCE AS OF 12-31-18	BALANCE AS OF 12-31-18		ADJUSTMENTS	JAN - DEC 2018 TOTAL COMPANY ADJUSTED @ 12/19
921A	BK DEPLETION-MINERALS & RIGHTS	(1,942,053)	1,343,790	(598,263)		(598,263)			(598,263)
930A	BOOK > TAX BASIS-PRTSHP INVEST	2,289,537		2,289,537		2,289,537			2,289,537
940K	1988-1990 IRS AUDIT SETTLEMENT	1,623		1,623		1,623	(c)	(1,623.00)	0
	Deferred 283 Adjustment		(642,076)	(642,076)		(642,076)			(642,076)
960F-XS	EXCESS ADFIT 283 - UNPROTECTED	(8,888,986)		(8,888,986)		(8,888,986)			(8,888,986)
	TOTAL ACCOUNT 2831	32,930,399	232,154	33,162,551	0	33,162,551		(16,977,460)	16,185,091
	ACCOUNT 2832:								
	SFAS 109 FLOW-THRU 283.3	54,730,848	385,843	55,116,691		55,116,691	(b)	(8,041,507)	47,075,184
	SFAS 109 EXCESS DFIT 283.4	8,888,986	62,666	8,951,652	0	8,951,652			8,951,652
	SFAS 109 - DEFD STATE INCOME TAXES	191,121,231	1,347,372	192,468,603	0	192,468,603			192,468,603
	TOTAL ACCOUNT 283	287,671,464	2,028,035	289,699,497	0	289,699,497		(25,018,967)	264,680,530
	Schedule E17-B	287,671,464							
	(b) Turk adjustment - See WP B 2-5-2								
	(c) Adjustments are nonapplicable for a base Filing		190	304,612,478	304,612,479	1			
	(d) Adjustments related to 2019 Excess		281	41,163,424	41,163,424	0			
	(e) Turk adjustment (See Wp F 1.3) plus 2019 depreciation adjustments		282	647,805,939	893,391,333	245,585,394			
	(f) AFUDC adjustments - See WP 2-1		283	289,699,497	289,699,500	3			
	(g) Adjustments related to 2019 Intangible Plant - See WP B 2-7								
				1,283,281,338	1,528,866,736	245,585,398			

1 Note: Purpose: Provides detail of Test Year and Pro forma Acct 281, 282, and 283

2 Note: Source of January - July 2018 amounts is PowerPlant Provision Software

3 Note: Source of Forecasted August - December 2018 amounts is Forecast Software

4 Note: The three digit number in column A is the Schedule M indicator from PowerPlant Provision Software

Supporting Schedule:
(a) Schedule E-17B

Recap Schedules:
(A) WP C-10-1

Southwestern Electric Power Company
Calculation of Current Income Tax Expense
Test Year Ending December 31, 2018
Docket No. 19-008-U

Schedule C-11

Explanation: A schedule showing the calculation of current federal and state income taxes charged to Operations for the test year and pro forma year.

		Total Company (A)	
Line No.	**Description**	**Test Year**	**Pro Forma Year (a) (b)**
1	Revenue (a)	1,831,204,180	1,100,365,282
2	O&M Expenses	1,191,324,700	501,231,996
3	Depreciation	239,107,852	234,732,181
4	Taxes Other than Income Taxes	102,213,261	101,238,419
5	Income Before Income Tax & Interest	298,558,367	263,162,686
6	Adjustments to Income		
7	Additions	137,052,970	57,768,555
8	Deductions	301,608,413	218,653,647
9	Taxable Income	134,002,924	102,277,594
10	State Tax Calculation		
11	Taxable Income	134,002,924	102,277,594
12	State Adjustments (Specify)	(149,025,000)	-
13	State Taxable Income	(15,022,076)	102,277,594
14	State Income Tax (before credits)	6,241,454	1,622,020
15	State Tax Adjustments (Specify)	(1,723,102)	1,511,890
16	Total State Income Tax	4,518,352	3,133,910
		4,518,352	
17	Federal Tax Calculation		
18	Taxable Income	129,484,572	99,143,684
19	Federal Adjustments (Specify)		
20	Federal Taxable Income	129,484,572	99,143,684
21	Federal Income Tax (before credits)	27,191,760	20,820,174
22	Federal Tax Adjustments (Specify)	(4,278,577)	-
23	Total Federal Income Tax	22,913,183	20,820,174
		22,913,183	
24	Total Current Income Tax	27,431,535	23,954,084

Supporting Schedules: -
(a) Schedule C-1
(b) WP C-11-1

Recap Schedules:
(A) Schedule C-1

Southwestern Electric Power Company
Calculation of Current Income Tax Expense
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP C-11-1

Line No.	Description	Amount (b)	Total Company Adjustment (b)	Adjusted Test Year
1	**Line 7. Additions:**			
2	Temporary Differences:			
3	390A CIAC - Book Receipts	2,384,038	-	2,384,038
4	380J Interest Expense Capitalized for Tax	7,543,620	-	7,543,620
5	532D BOOK/TAX UNIT OF PROPERTY ADJ-SEC 481 ADJ	3,470,000		3,470,000
6	520A Provision for Possible Revenue Refunds	1,611,191	(1,611,191)	-
7	520X PROV FOR RATE REFUND-TAX REFORM	29,008,073	(29,008,073)	-
8	520Y PROV FOR RATE REFUND-EXCESS PROTECTED	8,184,185	(8,184,185)	-
9	433C AR - FUEL OVER/UNDER RECOVERY	14,382,718	(14,382,718)	-
10	602A PROV WORKER'S COMP	303,757		303,757
11	605B Accrued Book Pension Expense	6,110,214	-	6,110,214
12	605E Supplemental Executive Retirement Plan	50,237	-	50,237
13	611E Accrued Mine Reclamation	730,554	(730,554)	-
14	612Y ACCRD COMPANYWIDE INCENTV PLAN	1,224,098		1,224,098
15	613E Accrued Book Vacation Pay	791,254	-	791,254
16	613K (ICDP) - INCENTIVE COMP DEFERRAL PLAN	23,455		23,455
17	615B ACCRUED INTEREST-LONG-TERM - FIN 48	107,036	(107,036)	-
18	615C ACCRUED INTEREST-SHORT-TERM - FIN 48	4,798	(4,798)	-
19	630M RATE CASE DEFD CHGS	1,664,838		1,664,838
20	641I ADVANCE RENTAL INC (CUR MO)	506,640		506,640
21	661R Reg Asset - SFAS 158 - Pensions	2,505,368	(2,505,368)	-
22	661S Reg Asset - SFAS 158 - SERP	28,786	(28,786)	-
23	664A REG ASSET-UND/REC ENVIRON ADJ CLAUSE-LA	80,108	(80,108)	-
24	664R REG ASSET-VALLEY DISTRICT DUE DILIGENCE	33,032	(33,032)	-
25	664V REG ASSET-NET CCS FEED STUDY COSTS	23,216	-	23,216
26	668P REG ASSET-LA FRP ASSET	54,955	(54,955)	-
27	669J REG ASSET-ENERGY EFFICIENCY RECOVERY	3,142,932	(3,142,932)	-
28	669X REG ASSET-SWEPCO SHIPE ROAD	816,101	(816,101)	-
29	669Y REG ASSET-2010 SEVERANCE COSTS-LA FRP	269,941	(269,941)	-
30	673J REG ASSET-WELSH/FLINT CRK ENVIRON DEF	1,167,656	(1,167,656)	-
31	673U REG ASSET-LA 2015 FRP-SPP DEFERRAL	940,921	(940,921)	-
32	673V REG ASSET-LA 2015 FRP-UNREC EQUITY	175,253	(175,253)	-
33	673Z REG ASSET-WELSH 2 TX-UNDEPR BAL	284,097	(284,097)	-
34	651I DISALLOWED COSTS-TX TRANS VEG MGT CST	246,212	(246,212)	-
35	651T DISALLOWED COSTS-TX CWIP FINBASED INCEN-TRANS	1,747,345	(1,747,345)	-
36	651W DISALLOWED COSTS-TX CWIP FINBASED INCEN-DIST	3,735,032	(3,735,032)	-
37	651X DISALLOWED COSTS-TX CWIP FINBASED INCEN-GEN	3,985,126	(3,985,126)	-
38	651Y DISALLOWED COSTS-TX RWIP FINBASED INCEN-TRANS	63,897	(63,897)	-
39	651Z DISALLOWED COSTS-TX RWIP FINBASED INCEN-DIST	84,669	(84,669)	-
40	653A DISALLOWED COSTS-TX RWIP FINBASED INCEN-GEN	94,092	(94,092)	-
41	690F REG ASSET-NBV-ARO-RETIRED PLANTS	4,153		4,153
42	900A Loss on Reacquired Debt	435,020	-	435,020
43	906F ACCRD OPEB COSTS - SFAS 158	1,412,367	(1,412,367)	-
44	906K Accrued SFAS 112 Post Employment Benefits	707,942	-	707,942
45	906P Accrued Book ARO Expense - SFAS 143	21,170,808	-	21,170,808
46	906Z SFAS 106 - MEDICARE SUBSIDY - (PPACA)-REG ASSET	311,098		311,098
47	914A SFAS 109 - Deferred SIT Liability	1,860,387	-	1,860,387
48	980J PSI-STOCK-BASED PLAN	191,609		191,609
49	711O Book Leases Capitalized for Tax	2,128,000	-	2,128,000
50	575E Mark-to-Market Book Gain-A/L-Tax Deferral	3,769,875	(3,769,875)	-
52	638A BOOK > TAX BASIS - EMA-A/C 283	164,078		164,078
53	Total Temporary Differences - Additions	129,734,782	(78,666,320)	51,068,462
54				
55	Permanent Differences:			
56	280A Excess Tax vs.S/L Book Depreciation	6,700,000	(618,095)	6,081,905
57	910B Non-deductible Meals, Travel and Entertainmet	618,188	-	618,188
58	Total Permanent Differences - Additions	7,318,188	(618,095)	6,700,093
59				
60	Total Additions (A)	137,052,970	(79,284,415)	57,768,555
61				
62	**Line 8. Deductions:**			
63	Temporary Differences:			
64	230A ACRS Benefit Normalized	707,000	(39,600,280)	(38,893,280)
65	280H BK PLANT IN SERVICE - SFAS 143 - ARO	22,143,214		22,143,214
66	320A ABFUDC	6,221,826	-	6,221,826
67	532C BOOK/TAX UNIT OF PROPERTY ADJ	63,990,000	-	63,990,000

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Line No.	Description		Amount (b)	Total Company Adjustment (b)		Adjusted Test Year	
68	534A Capitalized Relocation Costs		3,408,000	-		3,408,000	
69	910K Removal Costs		21,205,000	-		21,205,000	
70	533A TX AMORTIZATION POLLUTION CONTROL EQPT		2,877,000	(2,877,000)		-	
71	533J TX ACCEL AMORT-CAPITALIZED SOFTWARE		483,000	(483,000)		-	
72	921A BK DEPLETION-MINERALS & RIGHTS		5,392,003			5,392,003	
73	433D Louisiana - Fuel Over/Under Recovery		3,227	(3,227)		-	
74	605C Accrued Book Pension Costs - SFAS 158		2,505,368	(2,505,368)		-	
75	605F Accrued Supp Exec Retirement Plan Costs-SFAS 158		28,786	(28,786)		-	
76	605I ACCRD BK SUP. SAVINGS PLAN EXP		99,161			99,161	
77	605K Accrued Book Benefit Costs		12,972	-		12,972	
78	605O Accrued PSI Plan Expenses		2,200,062	-		2,200,062	
79	610A Book Provision Uncollectible Accounts		771,733	-		771,733	
80	615O BK DFL RAIL TRANS REV/EXP		141	(141)		-	
81	660F REG ASSET - SFAS 143 - ARO		779,209			779,209	
82	661T REG ASSET - SFAS 158 - OPEB		1,412,367	(1,412,367)		-	
83	670O REG ASSET-ENVIRONMENTAL CHEMICAL COST-AR		588,182	(588,182)		-	
84	672P REG ASSET-FACILITIES MAINT-SWEPCO LA		114,086	(114,086)		-	
85	673K REG ASSET-WELSH/FLINT CRK ENVIRON-CONTRA		335,311	(335,311)		-	
86	651F DISALLOWED COSTS-TURK PLANT		1,370,079	(1,370,079)		-	
87	651H DISALLOWED COSTS-TURK PLANT AUX BOILER		220,150	(220,150)		-	
88	651J DISALLOWED COSTS-TX DIST VEG MGT CST		24,276	(24,276)		-	
89	651K DISALLOWED COSTS-TX TRANS VEG MGT CST-AMORT		13,870	(13,870)		-	
90	651M DISALLOWED COSTS-TX DIST VEG MGT CST-AMORT		64,314	(64,314)		-	
91	651Q DISALLOWED COSTS-TX SERP COSTS		351,013	(351,013)		-	
92	651R DISALLOWED COSTS-TX DIST COSTS		183,982	(183,982)		-	
93	651S DISALLOWED COSTS-TX GEN COSTS		13,275,614	(13,275,614)		-	
94	900F BK DEFL-GAIN REACQUIRED DEBT		6,482			6,482	
95	906A ACCRD SFAS 106 PST RETIRE EXP		6,404,342			6,404,342	
96	911S Accrued Sales & Use Tax Reserve		311,500	(311,500)		-	
97	914B Reg Asset - SFAS 109 DSIT Liability		1,860,387	-		1,860,387	
98	930A BOOK > TAX BASIS-PRTSHP INVEST		840,000			840,000	
99	940X IRS CAPITALIZATION ADJUSTMENT		225,012			225,012	
100	980A RESTRICTED STOCK PLAN		208,193			208,193	
101	702A GOODWILL PER TAX		403,522			403,522	
102	710H AMORT ELEC PLT ACQ ADJS		35,623			35,623	
103	712K CAPITALIZED SOFTWARE COST-BOOK		2,349,587	7,584,352		9,933,939	
104	610V PROV-FAS 157 - A/L		15,837	(15,837)		-	
105	652G Reg Liability-Unrealized Mark-to-Market Gain-Deferral		3,754,037	(3,754,037)		-	
106							
107	Total Temporary Differences - Deductions		167,195,468	(59,948,068)		107,247,400	
108							
109	Permanent Differences:						
110	921G Accelerated Book Depletion		15,192,000	408,000		15,600,000	
111	910E NON-DEDUCT - MISCELLANEOUS		120,029	-		120,029	
112	980B RESTRICTED STOCK PLAN-TAX DEDUCTION		74,559	-		74,559	
113	Total Permanent Differences - Deductions		15,386,588	408,000		15,794,588	
114							
115	Interest Charges:						
116	Total Interest Charges		119,011,631	(23,399,972)		95,611,659	
117	Interest Charges Related to Non-Utility Property		(14,726)	14,726		-	
118	Interest Charges		119,026,357	(23,414,698)	(a)	95,611,659	(B)
119							
120	Total Deductions (A)		301,608,413	(82,954,766)		218,653,647	
121							
122							
123	**Line 12. State Adjustments:**						
124	Bonus Depreciation - Arkansas	(a)	(149,025,000)	63,120,981		(212,145,981)	
125							
126							
127	**Line 15. State Tax Adjustments:**						
128	Texas Gross Margin Income Taxes		1,169,079	342,811		1,511,890	
129	NOL Utilization - Arkansas		525,519	(525,519)		0	
130	NOL Utilization - Louisiana		(951,210)				
131	NOL Utilization - Oklahoma		(5,122)				
132	Other		(99,196)	99,196		0	
133	Total State Tax Adjustments	(A)	639,069	(83,512)		1,511,890	

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Line No.	Description		Amount (b)	Total Company Adjustment (b)	Adjusted Test Year
134					
135	**Line 22. Federal Tax Adjustments:**				
136	Tax Credit C/F		(677,769)		-
137	NOL-Reclass To/From Defd Tax Asset		(1,158,169)		-
138	FIN48 Per Items		432,721		-
139	Non FIN48		(1,541,827)		-
140	Other Current FIT Adj		(1,333,533)	-	-
141	Total Federal Tax Adjustments	(A)	(4,278,577)	-	-

Supporting Schedules:
(a) WP C-11-4
(b) WP C-12-5

Recap Schedules:
(A) Schedule C-11
(B) WP C-11-2

Southwestern Electric Power Company **WP C-11-2**
Interest Synchronization Calculation
Test Year Ending December 31, 2018
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Line No.	Description	Total Co. Adjusted Test Year	
1.	Pro Forma Rate Base (a)	5,942,303,243	
2.	Weighted Cost of Debt (b)	1.609%	
3.	Pro Forma Interest Expense (A)	95,611,659	(A)

Supporting Schedules:
(a) Schedule B-1
(b) WP D 1-5

Recap Schedules:
(A) WP C-11-1

Purpose: To provide calculation of interest expense deduction synchronized with rate base to determine allowable interest deduction in determining federal income tax expense

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For the Period: Jan 2018 thru Jul 2018 Actual, Aug-Dec Forecasted	**January - July 2018**	**Forecasted Aug - December 2018**	**7 Months Actual Plus 5 Months Forecasted 2018**
==			
Book Income	93,742,329.51	65,349,084.00	159,091,413.51
Tax Items	-		-
Book Income Before Tax	93,742,329.51	65,349,084.00	159,091,413.51
==			
EXCESS TAX vs BOOK DEPRECIATION			
230A ACRS BENEFIT NORMALIZED	7,644,000.00	(8,351,000.00)	(707,000.00)
280A EXCESS TX VS S/L BK DEPR	3,780,000.00	2,920,000.00	6,700,000.00
280H BK PLANT IN SERVICE - SFAS 143 - ARO	(23,154,213.88)	1,011,000.00	(22,143,213.88)
390A CIAC - BOOK RECEIPTS	1,261,037.94	1,123,000.00	2,384,037.94
Total EXCESS TAX vs BOOK DEPRECIATION	(10,469,175.94)	(3,297,000.00)	(13,766,175.94)
==			
AFUDC / INTEREST CAPITALIZED			
320A ABFUDC	(3,242,825.59)	(2,979,000.00)	(6,221,825.59)
330D AFUDC CAPITALIZED	(3,368,465.65)	(3,930,000.00)	(7,298,465.65)
380J INT EXP CAPITALIZED FOR TAX	4,849,619.62	2,694,000.00	7,543,619.62
Total AFUDC / INTEREST CAPITALIZED	(1,761,671.62)	(4,215,000.00)	(5,976,671.62)
==			
PERCENT REPAIR ALLOWANCE			
532A PERCENT REPAIR ALLOWANCE	(31,549,000.00)	(32,441,000.00)	(63,990,000.00)
532D BK/TX UNIT OF PROPERTY ADJ-SEC 481	3,353,000.00	117,000.00	3,470,000.00
534A CAPITALIZED RELOCATION COSTS	(1,988,000.00)	(1,420,000.00)	(3,408,000.00)
Total PERCENT REPAIR ALLOWANCE	(30,184,000.00)	(33,744,000.00)	(63,928,000.00)
==			
REMOVAL COSTS			
910K REMOVAL CST	(12,401,000.00)	(8,804,000.00)	(21,205,000.00)
Total REMOVAL COSTS	(12,401,000.00)	(8,804,000.00)	(21,205,000.00)
==			
ACCELERATED AMORTIZATION			
533A TX AMORT POLLUTION CONT EQPT	(2,877,000.00)		(2,877,000.00)
533J TXACCEL AMORT - CAPITALIXED SOFTWARE	(483,000.00)		(483,000.00)
Total ACCELERATED AMORTIZATION	(3,360,000.00)	-	(3,360,000.00)
==			
MINE DEVELOPMENT			
921A BK DEPLETION-MINERALS & RIGHTS	1,006,997.38	(6,399,000.00)	(5,392,002.62)
921G ACCEL BOOK DEPLETION	(8,400,000.00)	(6,792,000.00)	(15,192,000.00)
Total MINE DEVELOPMENT	(7,393,002.62)	(13,191,000.00)	(20,584,002.62)
==			
REVENUE REFUNDS			
520A PROVS POSS REV REFDS	1,611,191.29		1,611,191.29
520X PROV FOR RATE REFUND-TAX REFORM	29,008,073.17		29,008,073.17
520Y PROV FOR RATE REFUND-EXCESS PROTECTED	8,184,184.92		8,184,184.92
Total REVENUE REFUNDS	38,803,449.38	-	38,803,449.38
==			
DEFERRED FUEL COSTS			
433C AR - FUEL OVER/UNDER RECOVERY	(1,966,281.83)	16,349,000.00	14,382,718.17
433D LA - FUEL OVER/UNDER RECOVERY	(3,227.00)	-	(3,227.00)
Total DEFERRED FUEL COSTS	(1,969,508.83)	16,349,000.00	14,379,491.17
==			
EQUITY IN EARNINGS OF SUBSIDIARIES			
531A EQTY IN SUBSIDIARIES (US)	(18,290.05)		(18,290.05)
531B EQTY IN NON-CONSOLIDATION SUBS	(1,441,682.34)		(1,441,682.34)
Total EQUITY IN EARNINGS OF SUBSIDIARIES	(1,459,972.39)	-	(1,459,972.39)
==			
BOOK ACCRUALS			
602A PROV WORKER'S COMP	303,756.72		303,756.72
605B ACCRUED BK PENSION EXPENSE	3,941,213.58	2,169,000.00	6,110,213.58
605C ACCRUED BK PENSION COSTS - SFAS 158	(2,505,367.50)		(2,505,367.50)
605E SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN	50,236.68		50,236.68
605F ACCRD SUP EXEC RETIR PLAN COSTS-SFAS 158	(28,785.50)		(28,785.50)
605I ACCRD BK SUP. SAVINGS PLAN EXP	(99,160.73)		(99,160.73)
605K ACCRUED BK BENEFIT COSTS	(12,972.41)		(12,972.41)
605O ACCRUED PSI PLAN EXP	(2,200,062.36)		(2,200,062.36)
610A BK PROV UNCOLL ACCTS	(771,733.19)		(771,733.19)
611E ACCRUED MINE RECLAMATION	730,553.83		730,553.83
612Y ACCRD COMPANYWIDE INCENTV PLAN	(1,511,902.00)	2,736,000.00	1,224,098.00
613E ACCRUED BOOK VACATION PAY	791,254.18		791,254.18
613K (ICDP)-INCENTIVE COMP DEFERRAL PLAN	23,454.61		23,454.61
615B ACCRUED INTEREST-LONG-TERM - FIN 48	107,036.00	-	107,036.00
615C ACCRUED INTEREST-SHORT-TERM - FIN 48	4,798.00		4,798.00
Total BOOK ACCRUALS	(1,177,680.09)	4,905,000.00	3,727,319.91
==			
BOOK DEFERRALS			
615O BK DFL RAIL TRANS REV/EXP	(141.35)		(141.35)
630M RATE CASE DEFD CHGS	1,664,837.77		1,664,837.77
641I ADVANCE RENTAL INC (CUR MO)	1,131,640.20	(625,000.00)	506,640.20
660F REG ASSET - SFAS 143 - ARO	(779,208.67)		(779,208.67)
661R REG ASSET - SFAS 158 - PENSIONS	2,505,367.50		2,505,367.50

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661S REG ASSET - SFAS 158 - SERP	28,785.50		28,785.50
661T REG ASSET - SFAS 158 - OPEB	(1,412,367.46)		(1,412,367.46)
664A REG ASSET-UND/REC ENVIRON ADJ CLA	80,107.60		80,107.60
664R REG ASSET-VALLEY DISTRICT DUE DILIGENCE	33,032.03		33,032.03
664V REG ASSET-NET CCS FEED STUDY COSTS	23,215.80		23,215.80
668P REG ASSET-LA FRP ASSET	54,954.54		54,954.54
669J REG ASSET-ENERGY EFFICIENCY RECOVERY	1,782,932.41	1,360,000.00	3,142,932.41
669X REG ASSET-SWEPCO SHIPE ROAD	816,100.65		816,100.65
669Y REG ASSET-2010 SEVERANCE COSTS-LA FRP	269,940.70		269,940.70
670O REG ASSET-ENVIRONMENTAL CHEMICAL COST-AR	(588,182.20)		(588,182.20)
672P REG ASSET-FACILITIES MAINT-SWEPCO LA	(114,086.29)		(114,086.29)
673J REG ASSET-WELSH/FLINT CRK ENVIRON DEF	958,655.74	209,000.00	1,167,655.74
673K REG ASSET-WELSH/FLINT CRK ENVIRON-CONTRA	(335,310.64)		(335,310.64)
673U REG ASSET-LA 2015 FRP-SPP DEFERRAL	(375,078.66)	1,316,000.00	940,921.34
673V REG ASSET-LA 2015 FRP-UNREC EQUITY	175,253.45		175,253.45
673Z REG ASSET-WELSH 2 TX-UNDEPR BAL	284,097.46		284,097.46
Total BOOK DEFERRALS	6,204,546.08	2,260,000.00	8,464,546.08
======================================			
BOOK RESERVES			
651F DISALLOWED COSTS-TURK PLANT	(633,078.53)	(737,000.00)	(1,370,078.53)
651H DISALLOWED COSTS-TURK PLANT AUX BOILER	(220,150.00)		(220,150.00)
651I DISALLOWED COSTS-TX TRANS VEG MGT CST	246,212.07		246,212.07
651J DISALLOWED COSTS-TX DIST VEG MGT CST	(24,276.23)		(24,276.23)
651K DISALLOWED COSTS-TX TRANS VEG MGT CST-AMORT	(13,870.09)		(13,870.09)
651M DISALLOWED COSTS-TX DIST VEG MGT CST-AMORT	(64,313.61)		(64,313.61)
651Q DISALLOWED COSTS-TX SERP COSTS	(351,012.75)		(351,012.75)
651R DISALLOWED COSTS-TX DIST COSTS	(183,982.07)		(183,982.07)
651S DISALLOWED COSTS-TX GEN COSTS	(5,901,516.59)	(7,786,807.81)	(13,688,324.40)
651T DISALLOWED COSTS-TX CWIP FINBASED INCEN-TRANS	1,747,345.47		1,747,345.47
651W DISALLOWED COSTS-TX CWIP FINBASED INCEN-DIST	2,107,031.67	1,628,000.00	3,735,031.67
651X DISALLOWED COSTS-TX CWIP FINBASED INCEN-GEN	2,468,125.88	1,517,000.00	3,985,125.88
651Y DISALLOWED COSTS-TX RWIP FINBASED INCEN-TRANS	63,897.38		63,897.38
651Z DISALLOWED COSTS-TX RWIP FINBASED INCEN-DIST	84,668.54		84,668.54
653A DISALLOWED COSTS-TX RWIP FINBASED INCEN-GEN	94,091.98		94,091.98
Total BOOK RESERVES	(580,826.88)	(5,378,807.81)	(5,959,634.69)
======================================			
OTHER MISCELLANEOUS			
690F REG ASSET-NBV-ARO-RETIRED PLANTS	4,153.38		4,153.38
900A LOSS ON REACQUIRED DEBT	328,020.27	107,000.00	435,020.27
900F BK DEFL-GAIN REACQUIRED DEBT	(6,481.69)		(6,481.69)
906A ACCRD SFAS 106 PST RETIRE EXP	(3,379,341.65)	(3,025,000.00)	(6,404,341.65)
906F ACCRD OPEB COSTS - SFAS 158	1,412,367.46		1,412,367.46
906K ACCRD SFAS 112 PST EMPLOY BEN	707,942.00	-	707,942.00
906P ACCRD BOOK ARO EXPENSE - SFAS 143	21,170,807.56	-	21,170,807.56
906Z SFAS 106 - MEDICARE SUBSIDY - (PPACA)	311,097.50		311,097.50
911S ACCRUED SALES & USE TAX RESERVE	(311,500.00)		(311,500.00)
913D CHARITABLE CONTRIBUTION CARRYFRWD	(4,501,000.00)		(4,501,000.00)
914A SFAS 109 - DEFD SIT LIABILITY	1,860,387.00		1,860,387.00
914B REG ASSET - SFAS 109 DSIT LIAB	(1,860,387.00)		(1,860,387.00)
930A BOOK > TAX BASIS-PRTSHP INVEST	(840,000.00)		(840,000.00)
940X IRS CAPITALIZATION ADJUSTMENT	(225,012.00)		(225,012.00)
980A RESTRICTED STOCK PLAN	(208,192.70)		(208,192.70)
980J PSI - STOCK BASED COMP	191,609.08		191,609.08
Total OTHER MISCELLANEOUS	14,654,469.21	(2,918,000.00)	11,736,469.21
======================================			
PERMANENT SCHEDULE M's			
910B NON-DEDUCT MEALS AND T&E	225,188.20	393,000.00	618,188.20
910C NON-DEDUCT FINES&PENALTIES	72,695.76		72,695.76
910S NON-DEDUCT LOBBYING	417,852.91		417,852.91
980B PSI - STOCK BASED COMP	(74,558.55)		(74,558.55)
Total PERMANENT SCHEDULE M's	641,178.32	393,000.00	1,034,178.32
======================================			
TAX ACCRUALS			
711O BOOK LEASES CAPITALIZED FOR TAX	2,128,000.00		2,128,000.00
Total TAX ACCRUALS	2,128,000.00	-	2,128,000.00
======================================			
TAX DEFERRALS			
702A GOODWILL PER TAX	(235,522.00)	(168,000.00)	(403,522.00)
710H AMORT ELEC PLT ACQ ADJS	(35,623.00)	-	(35,623.00)
712K CAPITALIZED SOFTWARE COST-BOOK	(2,349,586.71)		(2,349,586.71)
Total TAX DEFERRALS	(2,620,731.71)	(168,000.00)	(2,788,731.71)
======================================			
MARK-TO-MARKET ADJUSTMENTS			
576E MARK & SPREAD-DEFL-283-A/L	3,769,875.00		3,769,875.00
610V PROV-FAS 157 - A/L	(15,837.00)		(15,837.00)
652G REG LIAB-UNREAL MTM GAIN-DEFL	(3,754,037.38)		(3,754,037.38)
Total MARK-TO-MARKET ADJUSTMENTS	0.62	-	0.62
======================================			

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For the Period: Jan 2018 thru Jul 2018 Actual, Aug-Dec Forecasted	**January - July 2018**	**Forecasted Aug - December 2018**	**7 Months Actual Plus 5 Months Forecasted 2018**
EMISSION ALLOWANCES			
638A BOOK > TAX BASIS - EMA-A/C 283	64,078.00	100,000.00	164,078.00
Total EMISSION ALLOWANCES	64,078.00	100,000.00	164,078.00
==			
Total Book/Tax Income Differences	(10,881,848.47)	(47,708,807.81)	(58,590,656.28)
==			
Taxable Income Before State Tax	82,860,481.04	17,640,276.19	100,500,757.23
State and Local Current Tax	2,577,721.18	-	2,577,721.18
Federal Taxable Income	80,282,759.86	17,640,276.19	97,923,036.05
Statutory Rate	21%	21%	21%
Current Federal Tax Before Credits	16,859,379.57	3,704,458.00	20,563,837.57
Credits	4,366,706.23		4,366,706.23
Current Federal Tax	12,492,673.34	3,704,458.00	16,197,131.34

Note: Includes utility operating and nonoperating income in determining current income tax expense

Southwestern Electric Power Company **WP C-11-4**
Calculation of Current State Income Tax Expense - Arkansas
Test Year Ending December 31, 2018
Docket No. 19-008-U

For the Period: Jan 2018 - Jul Actual, Aug 2018 - Dec Forecasted	January - July 2018	Forecasted Aug - December 2018	7 Months Actual Plus 5 Months Forecasted 2018 (A)	Adjustments (a) (b)	Adjusted Test Year 2019
Federal Taxable Income	82,860,481.04	21,137,000.00	103,997,481.04	(21,169,741.32)	82,827,739.72
Arkansas State Tax Adjustments:					
Bonus Depreciation - Arkansas	(93,346,000.00)	(55,679,000.00)	(149,025,000.00)	(63,120,981.00)	(212,145,981.00)
State Preference Differences			-		
Deductible State Tax Expense (States other than Arkansas)	(2,254,140.96)		(2,254,140.96)		(2,254,140.96)
Arkansas Taxable Income Before Apportionment	(12,739,659.92)	(34,542,000.00)	(47,281,659.92)	(84,290,722.32)	(131,572,382.24)
Arkansas Apportionment factor	24.3859%	24.3859%		24.3859%	24.3859%
Arkansas State Taxable income	(3,106,680.73)	(8,423,377.58)	(11,530,058.31)	(20,555,051.25)	(32,085,109.56)
Statutory Tax Rate - Arkansas	6.50%	6.50%	6.50%	6.50%	6.50%
Calculated State Tax Expense - Arkansas	(201,934.25)	(547,519.54)	(749,453.79)	(1,336,078.33)	(2,085,532.12)
Arkansas Tax Adjustments:					
IRS Audit Adjustments	525,518.60		525,518.60	(525,518.60)	-
Calculated Arkansas State Tax Expense after Adjustments	323,584.35	(547,519.54)	(223,935.19)	(1,861,596.93)	(2,085,532.12)
Reconciliation to Per Books:					
Reclassification from Operating to Non-Operating	423,689.47	27,519.54	451,209.01	(451,209.01)	-
Per Books Arkansas State Income Tax - Operating	747,273.82	(520,000.00)	227,273.82	(2,312,805.94)	(2,085,532.12)

Purpose: provides AR state income tax calculation

Supporting Schedules
(a) WP C-12-5
(b) WP C-11-1

Recap Schedules:
(A) WP C-11-1

Southwestern Electric Power Company
Calculation of Current State Income Tax Expense - Louisiana
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP C-11-5

For the Period: Jan 2018 thru Jul 2018 Actual, Aug-Dec Forecasted	**January - July 2018**	**Forecasted Aug - December 2018**	**7 Months Actual Plus 5Months Forecasted 2018**	**Adjustments (a)**	**Adjusted Test Year 2019**
Federal Taxable Income	82,860,481.04	21,137,000.00	103,997,481.04	(21,169,741.32)	82,827,739.72
Louisiana State Tax Adjustments:					
Deductible State Tax Expense (States other than Louisiana)	(1,007,195.25)		(1,007,195.25)		(1,007,195.25)
Louisiana Taxable Income Before Apportionment	81,853,285.79	21,137,000.00	102,990,285.79	(21,169,741.32)	81,820,544.47
Louisiana Apportionment factor	38.5100%	38.5100%		38.5100%	38.5100%
Louisiana State Taxable income	31,521,700.36	8,139,858.70	39,661,559.06	(8,152,467.38)	31,509,091.68
Statutory Tax Rate - Louisiana	8.00%	8.00%	8.00%	8.00%	8.00%
Calculated Louisiana State Tax Expense	2,521,736.03	651,188.70	3,172,924.73	(652,197.39)	2,520,727.33
Louisiana Tax Adjustments:					
NOL Utilization	(951,210.08)		(951,210.08)	951,210.08	-
Calculated Louisiana State Tax Expense after Adjustments	1,570,525.95	651,188.70	2,221,714.65	299,012.69	2,520,727.33
Reconciliation to Per Books:					
Reclassification from Operating to Non-Operating	836,199.07	53,811.30	890,010.37	(890,010.37)	-
Per Books Louisiana State Income Tax - Operating	2,406,725.02	705,000.00	3,111,725.02	(590,997.68)	2,520,727.33

Supporting Schedules
(a) WP C-12-5

Southwestern Electric Power Company
Calculation of Deferred Income Tax Expense
Test Year Ending December 31, 2018
Docket No. 19-008-U

Schedule C-12

Explanation: A schedule showing the calculation of deferred income tax expense. Amounts in the Credit columns should be identified as a turn-around of past deferrals or other.

		Total Company		Test Year		
Line No.	**Description**	**Test Year**	**Adjusted Test Year**	**Debit**	**Credit**	**Net**
1	State					
2	Current State Timing Differences					
3	Tax Depreciation (a)	(22,850,214)	16,750,066		(22,850,214)	(22,850,214)
4	Bonus Depreciation (a)	(149,025,000)	-		(149,025,000)	(149,025,000)
5	Other (Specify) (b)	(14,610,472)	(72,929,004)	129,734,782	(144,345,254)	(14,610,472)
6	Total Current Timing Differences	(186,485,686)	(56,178,938)	129,734,782	(316,220,468)	(186,485,686)
7	State Tax Rates, net of Fed Benefit	3.70%	3.68%	3.70%	3.70%	3.70%
8	Deferred State Income Tax Expense	3,252,160	2,067,385	(4,800,187)	8,052,347	3,252,160
9	Other Deferred State Income Tax Expense (c)	(2,821,346)	-	0	(2,821,346)	(2,821,346)
10	Deferred State Income Tax Expense (A)	430,814	2,067,385	(4,800,187)	5,231,001	430,814
11	Federal					
12	Current Federal Timing Differences					
13	Tax Depreciation	(22,850,214)	16,750,066	-	(22,850,214)	(22,850,214)
14	Other (Specify)	(14,610,472)	(72,929,004)	129,734,782	(144,345,254)	(14,610,472)
15	Total Current Timing Differences	(37,460,686)	(56,178,938)	129,734,782	(167,195,468)	(37,460,686)
16	Federal Tax Rates	21.00%	21.00%	21.00%	21.00%	21.00%
17	Deferred Federal Income Tax Expense	7,866,744	11,797,577	(27,244,304)	35,111,048	7,866,744
18	Other Deferred Federal Income Tax Expense (c)	(15,242,034)	(26,980,757)	3,068,586	(18,310,620)	(15,242,034)
19	Deferred Federal Income Tax Expense (A)	(7,375,290)	(15,183,180)	(24,175,718)	16,800,428	(7,375,290)
20	TOTAL DEFERRED INCOME TAX (A)	(6,944,476)	(13,115,795)	(28,975,905)	22,031,429	(6,944,476)

Purpose: provides calculation of deferred income tax expense for Test Year and Pro Forma Year.

Note: Turnaround timing differences are recorded as net, segergation is not avaliable

Supporting Schedules:
(a) WP C-11-1
(b) WP C-12-3
(c) WP C-12-2

Southwestern Electric Power Company
Calculation of Deferred Income Tax Expense
Test Year Ending December 31, 2018
Docket No. 19-008-U

Schedule C-12

Explanation: A schedule showing the calculation of deferred income tax expense. Amounts in the Credit columns should be identified as a turn-around of past deferrals or other.

		Pro Forma Year		
Line No.	**Description**	**Debit**	**Credit**	**Net**
1	State			
2	Current State Timing Differences			
3	Tax Depreciation (a)	38,893,280	(22,143,214)	16,750,066
4	Bonus Depreciation (a)			-
5	Other (Specify) (b)	51,068,462	(123,997,466)	(72,929,004)
6	Total Current Timing Differences	89,961,742	(146,140,680)	(56,178,938)
7	State Tax Rates, net of Fed Benefit	3.68%	3.68%	3.68%
8	Deferred State Income Tax Expense	(3,310,592)	5,377,977	2,067,385
9	Other Deferred State Income Tax Expense (c)	0	0	0
10	Deferred State Income Tax Expense (A)	(3,310,592)	5,377,977	2,067,385
11	Federal			
12	Current Federal Timing Differences			
13	Tax Depreciation	38,893,280	(22,143,214)	16,750,066
14	Other (Specify)	51,068,462	(123,997,466)	(72,929,004)
15	Total Current Timing Differences	89,961,742	(146,140,680)	(56,178,938)
16	Federal Tax Rates	21.00%	21.00%	21.00%
17	Deferred Federal Income Tax Expense	(18,891,966)	30,689,543	11,797,577
18	Other Deferred Federal Income Tax Expense (c)	1,232,648	(28,213,405)	(26,980,757)
19	Deferred Federal Income Tax Expense (A)	(17,659,318)	2,476,138	(15,183,180)
20	TOTAL DEFERRED INCOME TAX (A)	(20,969,910)	7,854,115	(13,115,795)

Purpose: provides calculation of deferred income ta:
Pro Forma Year.

Note: Turnaround timing differences are recorded as

Supporting Schedules:
(a) WP C-11-1
(b) WP C-12-3
(c) WP C-12-2

Recap Schedules:
(A) Schedule C-1

Southwestern Electric Power Company **WP C-12-1**
Calculation of Deferred Income Tax Expense - By Ferc Account
Test Year Ending December 31, 2018
Docket No. 19-008-U

DEBIT (CREDIT)

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN D	COLUMN E	COLUMN F	COLUMN G
	DEFERRED FEDERAL INCOME TAX ITEMS	JAN - JULY 2018 TOTAL COMPANY PER BOOKS	AUG - DEC 2018 TOTAL COMPANY PER BOOKS	JAN - DEC 2018 TOTAL COMPANY PER BOOKS	NON-UTILITY AMOUNT	JAN - DEC 2018 TOTAL COMPANY OPERATING PER BOOKS	ADJUSTMENTS	JAN - DEC 2018 TOTAL COMPANY ADJUSTED @ 12/19
	A/C 410 PROVISION FOR DEFERRED INCOME TAXES:							
533A	TX AMORT POLLUTION CONT EQPT	378,210		378,210		378,210	(378,210)	0
960F-XS	EXCESS ADFIT 281-PROTECTED	115,319		115,319		115,319		115,319
	TOTAL ACCOUNT 281 RELATED	493,529	0	493,529	0	493,529	(378,210)	115,319
230A	BOOK VS. TAX DEPRECIATION	13,323,206	(1,753,710)	11,569,496		11,569,496		11,569,496
230J	RELOCATION CST-SECTION 481(a)-CHANGE IN	32,626		32,626		32,626		32,626
260A	SPARE PARTS INVENTORY	1,119,967		1,119,967		1,119,967		1,119,967
280H	BK PLANT IN SERVICE - SFAS 143 - ARO	5,017,831	212,310	5,230,141		5,230,141		5,230,141
295C	GAIN/LOSS-ACRS/MACRS-BK/TX UNITY PROP	705,898		705,898		705,898		705,898
390A	CIAC BOOK RECEIPTS	6,244,894	235,830	6,480,724		6,480,724		6,480,724
320A	ABFUDC	680,993	(625,590)	55,403		55,403		55,403
380J	INTEREST EXPENSE CAPITALIZED FOR TAX	50,057,090	565,740	50,622,830		50,622,830		50,622,830
532C	BOOK/TAX UNIT OF PROPERTY ADJ	6,625,290	(6,812,610)	(187,320)		(187,320)		(187,320)
532D	BOOK/TAX UNIT OF PROPERTY ADJ SEC 481 ADJ		24,570	24,570		24,570		24,570
533J	TX ACCEL AMORT - CAPITALIZED SOFTWARE	101,430		101,430		101,430		101,430
534A	CAPITALIZED RELOCATION COSTS	417,480	(298,200)	119,280		119,280		119,280
910K	REMOVAL COSTS	2,604,210	(1,848,840)	755,370		755,370		755,370
960F-XS	EXCESS ADFIT - ACCOUNT 282	579,296,389		579,296,389		579,296,389		579,296,389
	TOTAL ACCOUNT 282 RELATED	666,227,303	(10,300,500)	655,926,804	0	655,926,804	0	655,926,804
011C-DFIT	TAX CREDIT C/F - DEF TAX ASSET	677,769		677,769		677,769		677,769
014C-AR	NOL-STATE C/F-DEF TAX ASSET-L/T - AR	218,137		218,137		218,137		218,137
014C-LA	NOL-STATE C/F-DEF TAX ASSET-L/T - LA	74,573		74,573		74,573	(74,573)	0
014C-OK	NOL-STATE C/F-DEF TAX ASSET-L/T -OK	265		265		265	(265)	0
575E	MTM BK GAIN-A/L-TAX DEFL	432,939		432,939		432,939	(432,939)	0
576E	MARK & SPREAD-DEFL-283-A/L	18,731		18,731		18,731	(18,731)	0
605B	ACCRUED BK PENSION EXPENSE	100	455,490	455,590		455,590		455,590
605C	ACCRUED BK PENSION COSTS - SFAS 158	14,006,851		14,006,851		14,006,851	(14,006,851)	0
638A	BOOK > TAX - EMA - A/C 283	66	21,000	21,066		21,066	(21,066)	0
660F	REG ASSET - SFAS 143 - ARO	163,634		163,634		163,634		163,634
661S	REG ASSET-SFAS 158-SERP	1,655		1,655		1,655	(1,655)	0
661T	REG ASSET-SFAS 158 - OPEB	830,870		830,870		830,870	(830,870)	0
664A	REG ASSET-UND/REC ENVIRON ADJ CLAUSE-L	59,891		59,891		59,891	(59,891)	0
664R	REG ASSET-VALLEY DISTRICT DUE DILIGENCE	7,544		7,544		7,544		7,544
669J	REG ASSET-ENERGY EFFICIENCY RECOVERY	142,625	285,600	428,225		428,225		428,225
670O	REG ASSET-ENVIRONMENTAL CHEMICAL COST	123,518		123,518		123,518		123,518
672P	REG ASSET-FACILITIES MAINT-SWEPCO LA	23,971		23,971		23,971	(23,971)	0
673J	REG ASSET-WELSH/FLINT CRK ENVIRON-DEF		43,890	43,890		43,890	(43,890)	0
673K	REG ASSET-WELSH/FLINT CRK ENVIRON-CONT	1,223,884		1,223,884		1,223,884	(1,223,884)	0
673U	REG ASSET-LA 2015 FRP-SPP DEFERRAL	78,767	276,360	355,127		355,127	(355,127)	0
673V	REG ASSET-LA 2015 FRP-UNREC EQUITY	14,401		14,401		14,401	(14,401)	0
711N	CAPITALIZED SOFTWARE COSTS-TAX	3,260		3,260		3,260		3,260
711O	BOOK LEASES CAPITALIZED FOR TAX	43,806		43,806		43,806		43,806
712K	CAPITALIZED SOFTWARE COST - BOOK	503,087		503,087		503,087		503,087
900F	BK DEFERRAL - GAIN ON REACQUIRED DEBT	4,163		4,163		4,163		4,163

Southwestern Electric Power Company
Calculation of Deferred Income Tax Expense - By Ferc Account
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP C-12-1

DEBIT (CREDIT)

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN D	COLUMN E	COLUMN F	COLUMN G
	DEFERRED FEDERAL INCOME TAX ITEMS	JAN - JULY 2018 TOTAL COMPANY PER BOOKS	AUG - DEC 2018 TOTAL COMPANY PER BOOKS	JAN - DEC 2018 TOTAL COMPANY PER BOOKS	NON-UTILITY AMOUNT	JAN - DEC 2018 TOTAL COMPANY OPERATING PER BOOKS	ADJUSTMENTS	JAN - DEC 2018 TOTAL COMPANY ADJUSTED @ 12/19
900A	LOSS ON REACQUIRED DEBT		22,470	22,470		22,470		22,470
906A	ACCRD SFAS 106 PST RETIRE EXP	709,662	(635,250)	74,412		74,412		74,412
906D	SFAS 106 PST RETIRE EXP - NON-DEDUCT CON	2,295,768		2,295,768		2,295,768		2,295,768
906K	ACCRD SFAS 112 PST EMPLOY BEN	768,164		768,164		768,164		768,164
913D	CHARITABLE CONTRIBUTION CARRYFORWARD	2,024,667		2,024,667		2,024,667		2,024,667
921A	BOOK DEPLETION - MINERALS & RIGHTS	1,153,722	1,551,446	2,705,168		2,705,168		2,705,168
930A	BOOK>TAX BASIS-PSHIP INVEST	176,400		176,400		176,400		176,400
960F-XS	EXCESS ADFIT - ACCOUNT 283	18,217,040		18,217,040		18,217,040		18,217,040
	TOTAL ACCOUNT 283 RELATED	43,999,929	2,021,006	46,020,936	0	45,050,192	(17,033,276)	28,016,916
433C	ARKANSAS FUEL OVER/UNDER RECOVERY	840,153	3,433,290	4,273,443		4,273,443	(4,273,443)	0
433D	LOUISIANA FUEL OVER/UNDER RECOVERY	921,425		921,425		921,425	(921,425)	0
460A	UNBILLED REVENUE	3,097,526		3,097,526		3,097,526	0	3,097,526
520A	PROVS POSS REV REFDS	3,931,402		3,931,402		3,931,402	(3,931,402)	0
520X	PROV FOR RATE REFUND-TAX REFORM	189,999		189,999		189,999	(189,999)	0
602A	PROV WORKERS COMP	122,312		122,312		122,312		122,312
605E	SUPPLEMENTAL EXECUTIVE RETIREMENT PLA	150,357		150,357		150,357		150,357
605F	ACCRD SUP EXEC RETIR PLAN COSTS-SFAS 15	165,897		165,897		165,897	(165,897)	0
605I	ACCRD BK SUP. SAVINGS PLAN EXP	187,539		187,539		187,539		187,539
605K	ACCRD BK BENEFIT COSTS	15,131		15,131		15,131		15,131
605O	ACCRUED PSI PLAN EXP	943,458		943,458		943,458		943,458
605P	STOCK BASED COMP-CAREE SHARES	449,178		449,178		449,178		449,178
610A	BK PROV UNCOLL ACCTS	348,228		348,228		348,228		348,228
610U	PROV TRADING CREDIT RISK - A/L	24		24		24	(24)	0
610V	PROV-FAS 157 - A/L	6,307		6,307		6,307		6,307
611E	ACCRUED MINE RECLAMATION	4,738,398		4,738,398		4,738,398		4,738,398
611G	DEFD COMENSATION-BOOK EXPENSE	237,310		237,310		237,310		237,310
612Y	ACCRD COMPANYWIDE INCENTV PLAN	2,973,967	574,560	3,548,527		3,548,527		3,548,527
613C	ACCRD ENVIORMENTAL LIAV-LONG TERM	3,659		3,659		3,659		3,659
613E	ACCRUED BOOK VACATION PAY	1,658,861		1,658,861		1,658,861		1,658,861
613F	ACCRD ENVIRONMENTAL LIAB-LONG TERM	477		477		477		477
613K	(ICDP)-INCENTIVE COMP DEFERRAL PLAN	21,932		21,932		21,932		21,932
615B	ACCRUED INTEREST-LONG-TERM - FIN 48	289,466		289,466		289,466	(289,466)	0
615C	ACCRUED INTEREST-SHORT-TERM-FIN 48	2,286		2,286		2,286		2,286
615E	ACCRUED STATE INCOME TAX EXP	665,674		665,674		665,674		665,674
615O	BK DFL RAIL TRANS REV/EXP	9,381		9,381		9,381	(9,381)	0
641I	ADVANCE RENTAL INCOME (CUR MO)	351,553	(131,250)	220,303		220,303		220,303
630J	DEFD STORM DAMAGE	3		3		3		3
630M	RATE CASE DEFD CHGS	167,125		167,125		167,125		167,125
641X	DEFD INCOME-DOLET HILLS MINING BUYOUT	38,207		38,207		38,207	(38,207)	0
651F	DISALLOWED COSTS - TURK PLANT	7,620,828	(154,770)	7,466,058		7,466,058		7,466,058
651H	DISALLOWED COSTS - TURK PLANT AUX BOILE	2,389,734		2,389,734		2,389,734		2,389,734
651I	DISALLOWED COSTS - TX TRANS VEG MGT CST	167,278		167,278		167,278		167,278
651J	DISALLOWED COSTS - TX DIST VEG MGT CST	582,997		582,997		582,997		582,997
651K	DISALLOWED COSTS - TX TRANS VEG MGT CST	2,913		2,913		2,913		2,913
651M	DISALLOWED COSTS - TX DIST VEG MGT CST-A	13,506		13,506		13,506		13,506
651Q	DISALLOWED COSTS-TX SERP COSTS	178,688		178,688		178,688		178,688
651R	DISALLOWED COSTS-TX DIST COSTS	81,128		81,128		81,128		81,128
651S	DISALLOWED COSTS-TX GEN COSTS	2,065,531	(674,730)	1,390,801		1,390,801		1,390,801

Southwestern Electric Power Company **WP C-12-1**
Calculation of Deferred Income Tax Expense - By Ferc Account
Test Year Ending December 31, 2018
Docket No. 19-008-U

DEBIT (CREDIT)

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN D	COLUMN E	COLUMN F	COLUMN G
	DEFERRED FEDERAL INCOME TAX ITEMS	JAN - JULY 2018 TOTAL COMPANY PER BOOKS	AUG - DEC 2018 TOTAL COMPANY PER BOOKS	JAN - DEC 2018 TOTAL COMPANY PER BOOKS	NON-UTILITY AMOUNT	JAN - DEC 2018 TOTAL COMPANY OPERATING PER BOOKS	ADJUSTMENTS	JAN - DEC 2018 TOTAL COMPANY ADJUSTED @ 12/19
651W	DISALLOWED COSTS-TX CWIP FINBASED INCEN-DIST		341,880	341,880		341,880		341,880
651X	DISALLOWED COSTS-TX CWIP FINBASED INCEN-GEN		318,570	318,570		318,570		318,570
651Z	DISALLOWED COSTS-TX RWIP FINBASED INCEI	161		161		161		161
652G	REG LIAB - UNREAL MTM GAIN - DEFL	1,582,400		1,582,400		1,582,400	(1,582,400)	0
653A	DISALLOWED COSTS-TX RWIP FINBASED INCEI	28		28		28		28
701A	AMORT-GOODWILL PER BOOKS	847,859		847,859		847,859		847,859
702A	GOODWILL PER TAX	49,460	(35,280)	14,180		14,180		14,180
906F	ACCRD OPEB COSTS - SFAS 158	14,578		14,578		14,578	(14,578)	0
710H	AMORT ELEC PLT ACQ ADJS	73,737		73,737		73,737		73,737
710W	BREM & HAUGH ACQUISITION ADJ - TX	2,487,299		2,487,299		2,487,299	(2,487,299)	0
906P	ACCRD BK ARO EXPENSE-SFAS 143	13,394,607		13,394,607		13,394,607		13,394,607
911F-FIn48	FIN 48 DSIT	82		82		82		82
911S	ACCRUED SALES & USE TAX RESERVE	376,901		376,901		376,901	(376,901)	0
911V	ACCRD SIT TX RESERVE-LNG-TERM-FIN 48	430,231		430,231		430,231	(430,231)	0
911W	ACCRD SIT TX RESERVE-LNG-TERM-FIN 48	7,850		7,850		7,850		7,850
940A	IRS AUDIT SETTLEMENT	1,726,827		1,726,827		1,726,827		1,726,827
940X	IRS CAPITALIZATION ADJUSTMENT	325,145		325,145		325,145		325,145
960E	AMT CREDIT - DEFERRED	124,850		124,850		124,850		124,850
960Z	NOL-DEFERRED TAX ASSET RECLASS	1,930,282		1,930,282		1,930,282		1,930,282
980A	RESTRICTED STOCK PLAN	113,694		113,694		113,694		113,694
980J	PSI-STOCK BASED COMP	45,042		45,042		45,042		45,042
	TOTAL ACCOUNT 190 RELATED	59,160,869	3,672,270	62,833,141	0	62,833,141	(14,710,653)	48,122,488
	TOTAL ACCOUNT 410	769,881,630	(4,607,224)	765,274,410	0	764,303,666	(32,122,139)	732,181,527
	A/C 411 PROVISION FOR DEFERRED INCOME TAXES:							
533A	TX AMORT POLLUTION CONT EQPT	(26,621,433)		(26,621,433)		(26,621,433)		(26,621,433)
960F-XS	EXCESS ADFIT 281 - PROTECTED	26,847,393		26,847,393		26,847,393		26,847,393
	TOTAL ACCOUNT 281 RELATED	225,960	0	225,960	0	225,960	0	225,960
230A	BOOK VS. TAX DEPRECIATION	(456,077,151)		(456,077,151)		(456,077,151)	(8,316,059)	(464,393,210)
280H	BK PLANT IN SERVICE - SFAS 143 - ARO	(9,282,189)		(9,282,189)		(9,282,189)		(9,282,189)
230I	CAPD INTEREST-SECTION 481(A)-CHANGE IN M	(508,691)		(508,691)		(508,691)		(508,691)
230X	R&D DEDUCTION - SEC 174	(5,653,309)		(5,653,309)		(5,653,309)		(5,653,309)
234Q	MACRS TAX DEPRECIATION - RAIL CARS	(1,850,110)		(1,850,110)		(1,850,110)		(1,850,110)
295A	GAIN/LOSS-ACRS/MACRS PROPERTY	(15,413,313)		(15,413,313)		(15,413,313)		(15,413,313)
295D	TAX LOSS ON PLANT RETIREMENTS/SALE	(1,075,254)		(1,075,254)		(1,075,254)		(1,075,254)
320A	ABFUDC	(31,728,396)		(31,728,396)		(31,728,396)		(31,728,396)
380J	INTEREST EXPENSE CAPITALIZED FOR TAX	(1,018,420)		(1,018,420)		(1,018,420)		(1,018,420)
390A	CIAC BOOK RECEIPTS	(264,818)		(264,818)		(264,818)		(264,818)
510H	PROPERTY TAX-NEW METHOD-BOOK	(156,934)		(156,934)		(156,934)		(156,934)
532A	PERCENT REPAIR ALLOWANCE	(6,050,696)		(6,050,696)		(6,050,696)		(6,050,696)
532C	BOOK/TAX UNIT OF PROPERTY ADJ	(29,973,065)		(29,973,065)		(29,973,065)		(29,973,065)
532D	BK/TX UNIT OF PROPERTY ADJ-SEC 481 ADJ	(15,345,545)		(15,345,545)		(15,345,545)		(15,345,545)
533J	TX ACCEL AMORT-CAPITALIZED SOFTWARE	(943,705)		(943,705)		(943,705)		(943,705)

Southwestern Electric Power Company **WP C-12-1**
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Test Year Ending December 31, 2018
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DEBIT (CREDIT)

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN D	COLUMN E	COLUMN F	COLUMN G
	DEFERRED FEDERAL INCOME TAX ITEMS	JAN - JULY 2018 TOTAL COMPANY PER BOOKS	AUG - DEC 2018 TOTAL COMPANY PER BOOKS	JAN - DEC 2018 TOTAL COMPANY PER BOOKS	NON-UTILITY AMOUNT	JAN - DEC 2018 TOTAL COMPANY OPERATING PER BOOKS	ADJUSTMENTS	JAN - DEC 2018 TOTAL COMPANY ADJUSTED @ 12/19
534A	CAPITALIZED RELOCATION COSTS	(4,924,105)		(4,924,105)		(4,924,105)		(4,924,105)
611E	ACCRUED MINE RECLAMATION	(153,416)		(153,416)		(153,416)	153,416	0
662A	WRITE-OFF RE SFAS 71	(4,472,232)		(4,472,232)		(4,472,232)		(4,472,232)
662B	SFAS 109 WRITE-OFF RE SFAS 71	(1,151,330)		(1,151,330)		(1,151,330)		(1,151,330)
680A	JOINT VENTURES-SYS FUEL PRJ-TX	(9,146)		(9,146)		(9,146)	9,146	0
690F	REG ASSET-NBV-ARO-RETIRED PLANTS	(72,019)		(72,019)		(72,019)		(72,019)
910J	INTEREST EXPENSE - COAL CARS	(5,671,803)		(5,671,803)		(5,671,803)		(5,671,803)
910K	REMOVAL COSTS	(28,164,383)		(28,164,383)		(28,164,383)		(28,164,383)
910W	REMOVAL COSTS REV SFAS 143-ARO	(4,226)		(4,226)		(4,226)		(4,226)
921A	BOOK DEPLETION - MINERALS & RIGHTS	(211,469)		(211,469)		(211,469)		(211,469)
960F-XS	EXCESS ADFIT - ACCOUNT 282	(38,686,259)		(38,686,259)		(38,686,259)	(27,826,648)	(66,512,907)
	TOTAL ACCOUNT 282 RELATED	(658,861,986)	0	(658,861,984)	0	(658,861,984)	(35,980,145)	(694,842,129)
014C-AR	NOL-STATE C/F-DEF TAX ASSET-L/T - AR	(755,356)		(755,356)		(755,356)		(755,356)
014C-LA	NOL-STATE C/F-DEF TAX ASSET-L/T - LA	(6,248,226)		(6,248,226)		(6,248,226)	6,248,226	0
014C-OK	NOL-STATE C/F-DEF TAX ASSET-L/T - OK	(33,872)		(33,872)		(33,872)	33,872	0
575E	MTM BK GAIN - A/L - TAX DEFL	(1,581,591)		(1,581,591)		(1,581,591)	1,581,591	0
576F	MARK &SPREAD-DEFL-190-A/L	(24,917)		(24,917)		(24,917)		(24,917)
605B	ACCRUED BK PENSION EXPENSE	(12,972,725)		(12,972,725)		(12,972,725)		(12,972,725)
638A	BOOK > TAX - EMA - A/C 283	(25,815)		(25,815)		(25,815)		(25,815)
660F	REG ASSET-SFAS 143-ARO	(628,515)		(628,515)		(628,515)		(628,515)
661R	REG ASSET - SFAS 158 - PENSIONS	(14,006,851)		(14,006,851)		(14,006,851)	14,006,851	0
661S	REG ASSET - SFAS 158 - SERP	(165,897)		(165,897)		(165,897)	165,897	0
661T	REG ASSET - SFAS 158 - OPEB	(8,804)		(8,804)		(8,804)	8,804	0
664A	REG ASSET-UND/REC ENVIRON ADJ CLAUSE-L	(111,293)		(111,293)		(111,293)	111,293	0
664R	REG ASSET-VALLEY DISTRICT DUE DILIGENCE	(19,105)		(19,105)		(19,105)	19,105	0
664V	REG ASSET-NET CCS FEED STUDY COSTS	(70,686)		(70,686)		(70,686)		(70,686)
668P	REG ASSET-LA FRP ASSET	(19,234)		(19,234)		(19,234)	19,234	0
669J	REG ASSET-ENERGY EFFICIENCY RECOVERY	(1,089,580)		(1,089,580)		(1,089,580)	1,089,580	0
669X	REG ASSET-SWEPCO SHIPE ROAD	(628,397)		(628,397)		(628,397)	628,397	0
669Y	REG ASSET-2010 SEVERANCE COSTS-LA FRP	(94,479)		(94,479)		(94,479)	94,479	0
670O	REG ASSET-ENVIRONMENTAL CHEMICAL COST	(297,189)		(297,189)		(297,189)	297,189	0
672P	REG ASSET-FACILITIES MAINT-SWEPCO LA	(77,239)		(77,239)		(77,239)	77,239	0
673J	REG ASSET-WELSH/FLINT CRK ENVIRON-DEF	(3,499,093)		(3,499,093)		(3,499,093)	3,499,093	0
673U	REG ASSET-LA 2015 FRP-SPP DEFERRAL	(660,821)		(660,821)		(660,821)	660,821	0
673V	REG ASSET-LA 2015 FRP-UNREC EQUITY	(36,803)		(36,803)		(36,803)	36,803	0
673Z	REG ASSET-WELSH 2 TX-UNDEPR BAL	(2,520,399)		(2,520,399)		(2,520,399)	2,520,399	0
711O	BOOK LEASES CAPITALIZED FOR TAX	(734,799)		(734,799)		(734,799)	734,799	0
712K	CAPITALIZED SOFTWARE COST - BOOK	(4,640,006)		(4,640,006)		(4,640,006)		(4,640,006)
900A	LOSS ON REACQUIRED DEBT	(721,372)		(721,372)		(721,372)		(721,372)
906A	ACCRD SFAS 106 PST RETIRE EXP	(3,398,911)		(3,398,911)		(3,398,911)		(3,398,911)
906D	SFAS 106 PST RETIRE EXP - NON-DEDUCT CON	(1,694)		(1,694)		(1,694)		(1,694)
906F	ACCRD OPEB COSTS - SFAS 158	(836,643)		(836,643)		(836,643)		(836,643)
906K	ACCRD SFAS 112 PST EMPLOY BEN	(226,060)		(226,060)		(226,060)		(226,060)
906Z	SFAS 106 - MEDICARE SUBSIDY - (PPACA)-REG	(587,974)		(587,974)		(587,974)		(587,974)
930A	BOOK > TAX BASIS-PRTSHP INVEST	(1,408,758)		(1,408,758)		(1,408,758)		(1,408,758)
960F-XS	EXCESS ADFIT 283 - UNPROTECTED	(27,106,027)		(27,106,027)		(27,106,027)		(27,106,027)
	TOTAL ACCOUNT 283 RELATED	(85,239,134)	0	(85,239,131)	0	(78,201,677)	25,551,574	(52,650,103)

Southwestern Electric Power Company **WP C-12-1**
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DEBIT (CREDIT)

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN D	COLUMN E	COLUMN F	COLUMN G
	DEFERRED FEDERAL INCOME TAX ITEMS	JAN - JULY 2018 TOTAL COMPANY PER BOOKS	AUG - DEC 2018 TOTAL COMPANY PER BOOKS	JAN - DEC 2018 TOTAL COMPANY PER BOOKS	NON-UTILITY AMOUNT	JAN - DEC 2018 TOTAL COMPANY OPERATING PER BOOKS	ADJUSTMENTS	JAN - DEC 2018 TOTAL COMPANY ADJUSTED @ 12/19
433C	AR-FUELOVER/UNDER RECOVERY	(2,396,431)		(2,396,431)		(2,396,431)		(2,396,431)
433D	LOUISIANA FUEL OVER/UNDER RECOVERY	(920,748)		(920,748)		(920,748)	920,748	0
520A	PROVS POSS REV REFDS	(2,547,536)		(2,547,536)		(2,547,536)	2,547,536	0
520X	PROV FOR RATE REFUND-TAX REFORM	(6,281,694)		(6,281,694)		(6,281,694)		(6,281,694)
520Y	PROV FOR RATE REFUND -EXCESS PROTECTE	(1,718,679)		(1,718,679)		(1,718,679)		(1,718,679)
602A	PROV WORKERS COMP	(120,427)		(120,427)		(120,427)		(120,427)
605E	SUPPLEMENTAL EXECUTIVE RETIREMENT PLA	(11,101)		(11,101)		(11,101)		(11,101)
605F	ACCRD SUP EXEC RETIR PLAN COSTS-SFAS 15	(1,655)		(1,655)		(1,655)		(1,655)
605I	ACCRD BK SUP. SAVINGS PLAN EXP	(4,509)		(4,509)		(4,509)		(4,509)
605O	ACCRUED PSI PLAN EXP	(13,761)		(13,761)		(13,761)		(13,761)
610A	BK PROV UNCOLL ACCTS	(41)		(41)		(41)		(41)
610V	PROV-FAS 157 - A/L	(3,220)		(3,220)		(3,220)		(3,220)
612Y	ACCRD COMPANYWIDE INCENTV PLAN	(1,395,129)		(1,395,129)		(1,395,129)		(1,395,129)
613E	ACCRUED BOOK VACATION PAY	(337,347)		(337,347)		(337,347)		(337,347)
613K	(ICDP)-INCENTIVE COMP DEFERRAL PLAN	(12,446)		(12,446)		(12,446)		(12,446)
615B	ACCRUED INTEREST-LONG-TERM - FIN 48	(311,833)		(311,833)		(311,833)	311,833	0
615C	ACCRUED INTEREST-SHORT-TERM-FIN 48	(1,055)		(1,055)		(1,055)		(1,055)
615E	ACCRUED STATE INCOME TAX EXP	(914,236)		(914,236)		(914,236)		(914,236)
615O	BK DFL RAIL TRANS REV/EXP	(9,352)		(9,352)		(9,352)	9,352	0
630J	DEFD STORM DAMAGE	(1)		(1)		(1)		(1)
630M	RATE CASE DEFD CHGS	(1,512,825)		(1,512,825)		(1,512,825)		(1,512,825)
641I	ADVANCE RENTAL INCOME (CUR MO)	(442,028)		(442,028)		(442,028)		(442,028)
651I	DISALLOWED COSTS - TX TRANS VEG MGT CS	(51,705)		(51,705)		(51,705)	51,705	0
651K	DISALLOWED COSTS - TX TRANS VEG MGT CS	(6,547)		(6,547)		(6,547)	6,547	0
651M	DISALLOWED COSTS - TX DIST VEG MGT CST-/	(34,450)		(34,450)		(34,450)	34,450	0
651Q	DISALLOWED COSTS-TX SERP COSTS	(33,501)		(33,501)		(33,501)	33,501	0
651R	DISALLOWED COSTS-TX DIST COSTS	(10,040)		(10,040)		(10,040)	10,040	0
651T	DISALLOWED COSTS-TX CWIP FINBASED INCE	(366,943)		(366,943)		(366,943)	366,943	0
651W	DISALLOWED COSTS-TX CWIP FINBASED INCE	(442,477)		(442,477)		(442,477)	442,477	0
651X	DISALLOWED COSTS-TX CWIP FINBASED INCE	(518,306)		(518,306)		(518,306)	518,306	0
651Y	DISALLOWED COSTS-TX RWIP FINBASED INCE	(13,418)		(13,418)		(13,418)	13,418	0
651Z	DISALLOWED COSTS-TX RWIP FINBASED INCE	(17,941)		(17,941)		(17,941)	17,941	0
652G	REG LIAB - UNREAL MTM GAIN - DEFL	(434,617)		(434,617)		(434,617)	434,617	0
653A	DISALLOWED COSTS-TX RWIP FINBASED INCE	(19,787)		(19,787)		(19,787)	19,787	0
702A	GOODWILL PER TAX	(409,799)		(409,799)		(409,799)		(409,799)
906P	ACCRD BK ARO EXPENSE-SFAS 143	(4,854,325)		(4,854,325)		(4,854,325)		(4,854,325)
911F-FIn48	FIN 48 DEFD STATE INCOME TAXES	(13,952)		(13,952)		(13,952)	13,952	0
911S	ACCRUED SALES & USE TAX RESERVE	(267,876)		(267,876)		(267,876)		(267,876)
911V	ACCRD SIT TX RESERVE-LNG-TERM-FIN 48	(536,874)		(536,874)		(536,874)	536,874	0
911W	ACCRD SIT TX RESERVE-SHRT-TERM-FIN 48	(340)		(340)		(340)	340	0
940A	IRS AUDIT SETTLEMENT	(370,584)		(370,584)		(370,584)		(370,584)
940K	1988-1990 IRS AUDIT SETTLEMENT	(1,082)		(1,082)		(1,082)		(1,082)
940X	IRS CAPITALIZATION ADJUSTMENT	(3,968)		(3,968)		(3,968)		(3,968)
980A	RESTRICTED STOCK PLAN	(26,962)		(26,962)		(26,962)		(26,962)
980J	PSI-STOCK BASED COMP	(40,648)		(40,648)		(40,648)		(40,648)
	TCJA-ACCT 1902001-MJE	(1,079,457)		(1,079,457)		(1,079,457)		(1,079,457)
	TOTAL ACCOUNT 190 RELATED	(28,511,649)	0	(28,511,653)	0	(28,511,653)	6,290,367	(22,221,286)

Southwestern Electric Power Company
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	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN D	COLUMN E	COLUMN F	COLUMN G
	DEFERRED FEDERAL INCOME TAX ITEMS	JAN - JULY 2018 TOTAL COMPANY PER BOOKS	AUG - DEC 2018 TOTAL COMPANY PER BOOKS	JAN - DEC 2018 TOTAL COMPANY PER BOOKS	NON-UTILITY AMOUNT	JAN - DEC 2018 TOTAL COMPANY OPERATING PER BOOKS	ADJUSTMENTS	JAN - DEC 2018 TOTAL COMPANY ADJUSTED @ 12/19
	DEFERRED TO CURRENT ADJUSTMENT							
	RECLASS FROM CURRENT TO DEFERRED		981,505	981,505		981,505		981,505
	TOTAL DEFERRED TO CURRENT ADJ	0	981,505	981,505	0	981,505	0	981,505
	TOTAL ACCOUNT 411	(772,386,809)	981,505	(771,405,303)	0	(765,349,354)	(4,138,204)	(769,487,558)
	A/C 411.4 INVESTMENT TAX CREDIT ADJUST. :							
012A	SEC ALLOC - ITC - 10%	(829,626)	(414,770)	(1,244,396)		(1,244,396)	(857,639)	(2,102,035)
	TOTAL ACCOUNT 411.4	(829,626)	(414,770)	(1,244,396)	0	(1,244,396)	(857,639)	(2,102,035)
	TOTAL ACCOUNT 410, 411, AND 411.4	(3,334,805)	(4,040,489)	(7,375,289)	0	(2,290,084)	(37,117,982)	(39,408,066)
	4101001	768,082,927	7,183,904	775,266,831				
	4102001	2,024,667	0	2,024,667				
	4111001	(771,533,311)	(10,809,623)	(782,342,934)				
	4112001	(1,079,457)	0	(1,079,457)				
	4114001	(829,626)	(414,770)	(1,244,396)				
		(3,334,800)	(4,040,489)	(7,375,289)				
	Note: Ties to Federal only. Does not include State		0					

Southwestern Electric Power Company
Other Deferred Income Tax Adjustments
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WP C-12-2

		Total Company					
		Test Year		Adjustments		Adjusted Test Year	
Line No.	Description	State	Federal	State	Federal	State	Federal
1	Other Deferred Tax Expense:						
2	Recognition of Flow-through Deferred State Inc	(2,821,346)	-	2,821,346	-	-	-
3	Taxes for all SWEPCo state jurisdictions			-	-	-	-
4	Deferred ITC		(1,244,626)	-	857,869	-	(386,757)
5	Amortization of Excess Deferred FIT		(16,975,523)	-	(10,851,125)	-	(27,826,648)
6	NOL - Deferred Tax Asset Reclass		1,158,169	-	(1,158,169)	-	-
7	Tax Credit C/F - Def Tax Asset		677,769		(677,769)		-
8	AMT Credit - Def		124,850		-		124,850
9	IRS Audit Settlement		575,835				575,835
10	Deferred FIT Adjustment		531,963				531,963
11	Deferred FIT on Deferred State Income Taxes	-	(90,471)	-	90,471	-	-
12	Deferred FIT on Deferred State Income Taxes-FIN 48		-	-	-	-	
13	Rounding		-	-		-	-
14	Deferred Taxes Recorded	(2,821,346)	(15,242,034)	2,821,346	(11,738,723)	-	(26,980,757)

Recap Schedules:
(A) Schedule C-12

Southwestern Electric Power Company **WP C-12-3**
Calculation of Deferred Income Tax Expense - Temporary Differences- Other
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		Total Company	
Line No.	Description	Test Year (a)	Adjusted Test Year (a)
1	**Lines 4. and 19. Other:**		
2			
3	390A CIAC - Book Receipts	2,384,038	2,384,038
4	380J Interest Expense Capitalized for Tax	7,543,620	7,543,620
5	532D BOOK/TAX UNIT OF PROPERTY ADJ-SEC 481 ADJ	3,470,000	3,470,000
6	520A Provision for Possible Revenue Refunds	1,611,191	-
7	520X PROV FOR RATE REFUND-TAX REFORM	29,008,073	-
8	520Y PROV FOR RATE REFUND-EXCESS PROTECTED	8,184,185	-
9	602A PROV WORKER'S COMP	303,757	303,757
10	605B Accrued Book Pension Expense	6,110,214	6,110,214
11	605E Supplemental Executive Retirement Plan	50,237	50,237
12	611E Accrued Mine Reclamation	730,554	-
13	612Y ACCRD COMPANYWIDE INCENTV PLAN	1,224,098	1,224,098
14	613E Accrued Book Vacation Pay	791,254	791,254
15	613K (ICDP) - INCENTIVE COMP DEFERRAL PLAN	23,455	23,455
16	615C ACCRUED INTEREST-SHORT-TERM - FIN 48	4,798	-
17	630M RATE CASE DEFD CHGS	1,664,838	1,664,838
18	661R Reg Asset - SFAS 158 - Pensions	2,505,368	-
19	661S Reg Asset - SFAS 158 - SERP	28,786	-
20	664A REG ASSET-UND/REC ENVIRON ADJ CLAUSE-LA	80,108	-
21	664R REG ASSET-VALLEY DISTRICT DUE DILIGENCE	33,032	-
22	664V REG ASSET-NET CCS FEED STUDY COSTS	23,216	23,216
23	668P REG ASSET-LA FRP ASSET	54,955	-
24	669J REG ASSET-ENERGY EFFICIENCY RECOVERY	3,142,932	-
25	669X REG ASSET-SWEPCO SHIPE ROAD	816,101	-
26	669Y REG ASSET-2010 SEVERANCE COSTS-LA FRP	269,941	-
27	673J REG ASSET-WELSH/FLINT CRK ENVIRON DEF	1,167,656	-
28	673U REG ASSET-LA 2015 FRP-SPP DEFERRAL	940,921	-
29	673V REG ASSET-LA 2015 FRP-UNREC EQUITY	175,253	-
30	673Z REG ASSET-WELSH 2 TX-UNDEPR BAL	284,097	-
31	651I DISALLOWED COSTS-TX TRANS VEG MGT CST	246,212	-
32	651T DISALLOWED COSTS-TX CWIP FINBASED INCEN-TRANS	1,747,345	-
33	651W DISALLOWED COSTS-TX CWIP FINBASED INCEN-DIST	3,735,032	-
34	651X DISALLOWED COSTS-TX CWIP FINBASED INCEN-GEN	3,985,126	-
35	651Y DISALLOWED COSTS-TX RWIP FINBASED INCEN-TRANS	63,897	-
36	651Z DISALLOWED COSTS-TX RWIP FINBASED INCEN-DIST	84,669	-
37	653A DISALLOWED COSTS-TX RWIP FINBASED INCEN-GEN	94,092	-
38	690F REG ASSET-NBV-ARO-RETIRED PLANTS	4,153	4,153
39	900A Loss on Reacquired Debt	435,020	435,020
40	906K Accrued SFAS 112 Post Employment Benefits	707,942	707,942
41	906P Accrued Book ARO Expense - SFAS 143	21,170,808	21,170,808
42	906Z SFAS 106 - MEDICARE SUBSIDY - (PPACA)-REG ASSET	311,098	311,098
43	914A SFAS 109 - Deferred SIT Liability	1,860,387	1,860,387
44	980J PSI-STOCK-BASED PLAN	191,609	191,609
45	711O Book Leases Capitalized for Tax	2,128,000	2,128,000
46	575E Mark-to-Market Book Gain-A/L-Tax Deferral	3,769,875	-
47	320A ABFUDC	(6,221,826)	(6,221,826)
48	532C BOOK/TAX UNIT OF PROPERTY ADJ	(63,990,000)	(63,990,000)
49	534A Capitalized Relocation Costs	(3,408,000)	(3,408,000)
50	910K Removal Costs	(21,205,000)	(21,205,000)
51	533A TX AMORTIZATION POLLUTION CONTROL EQPT	(2,877,000)	-
52	533J TX ACCEL AMORT-CAPITALIZED SOFTWARE	(483,000)	-
53	921A BK DEPLETION-MINERALS & RIGHTS	(5,392,003)	(5,392,003)
54	433C Arkansas - Fuel Over/Under Recovery	14,382,718	-
55	433D Louisiana - Fuel Over/Under Recovery	(3,227)	-
56	605C Accrued Book Pension Costs	(2,505,368)	-
57	605F Accrued Supp Exec Retirement Plan Costs-SFAS 158	(28,786)	-

Southwestern Electric Power Company **WP C-12-3**
Calculation of Deferred Income Tax Expense - Temporary Differences- Other
Test Year Ending December 31, 2018
Docket No. 19-008-U

Line No.	Description		Total Company Test Year (a)	Adjusted Test Year (a)
58	605I ACCRD BK SUP. SAVINGS PLAN EXP		(99,161)	(99,161)
59	605K Accrued Book Benefit Costs		(12,972)	(12,972)
60	605O Accrued PSI Plan Expenses		(2,200,062)	(2,200,062)
61	610A Book Provision Uncollectible Accounts		(771,733)	(771,733)
62	615O BK DFL RAIL TRANS REV/EXP		(141)	-
63	615B Accrued Interest Long-Term - FIN 48		107,036	-
64	641I Advance Rental Income		506,640	506,640
65	660F Reg Asset - SFAS 143 - ARO		(779,209)	(779,209)
66	661T REG ASSET - SFAS 158 - OPEB		(1,412,367)	-
67	670O REG ASSET-ENVIRONMENTAL CHEMICAL COST-AR		(588,182)	-
68	672P REG ASSET-FACILITIES MAINT-SWEPCO LA		(114,086)	-
69	673K REG ASSET-WELSH/FLINT CRK ENVIRON-CONTRA		(335,311)	-
70	651F DISALLOWED COSTS-TURK PLANT		(1,370,079)	-
71	651H DISALLOWED COSTS-TURK PLANT AUX BOILER		(220,150)	-
72	651J DISALLOWED COSTS-TX DIST VEG MGT CST		(24,276)	-
73	651K DISALLOWED COSTS-TX TRANS VEG MGT CST-AMORT		(13,870)	-
74	651M DISALLOWED COSTS-TX DIST VEG MGT CST-AMORT		(64,314)	-
75	651Q DISALLOWED COSTS-TX SERP COSTS		(351,013)	-
76	651R DISALLOWED COSTS-TX DIST COSTS		(183,982)	-
77	651S DISALLOWED COSTS-TX GEN COSTS		(13,275,614)	-
78	900F Book Deferral - Gain on Reacquired Debt		(6,482)	(6,482)
79	906A ACCRD SFAS 106 PST RETIRE EXP		(6,404,342)	(6,404,342)
80	906F Accrued OPEB Costs - SFAS 158		1,412,367	-
81	911S Accrued Sales & Use Tax Reserve		(311,500)	-
82	914B Reg Asset - SFAS 109 DSIT Liability		(1,860,387)	(1,860,387)
83	930A BOOK > TAX BASIS-PRTSHP INVEST		(840,000)	(840,000)
84	940X IRS CAPITALIZATION ADJUSTMENT		(225,012)	(225,012)
85	980A RESTRICTED STOCK PLAN		(208,193)	(208,193)
86	702A GOODWILL PER TAX		(403,522)	(403,522)
87	710H AMORT ELEC PLT ACQ ADJS		(35,623)	(35,623)
88	712K CAPITALIZED SOFTWARE COST-BOOK		(2,349,587)	(9,933,939)
89	610V PROV-FAS 157 - A/L		(15,837)	-
90	652G Reg Liability-Unrealized Mark-to-Market Gain-Deferral		(3,754,037)	-
91	638A Book > Tax Basis - EMA-A/C 283		164,078	164,078
92				
93	Total	(A)	(14,610,472)	(72,929,004)

Supporting Schedules:
(a) WP C-11-1

Recap Schedules:
(A) Schedule C-12

Southwestern Electric Power Company **WP C-12-4**
Calculation of Income Tax Expense - Operating Income Adj for Factoring
Test Year Ending December 31, 2018
Docket No. 19-008-U

Effective State Tax Ra 0.046779

For the Period: Jan 2018 thru Jul 2018 Actual, Aug-Dec Forecasted	**January - July 2018**	**Forecasted Aug - December 2018**	**7 Months Actual Plus 5 Months Forecasted 2008**	**Federal Tax Effect**	**(AR, OK, LA, NE) State Tax Effect (4.6779%)**	**Total Tax Effect (25.6779%)**
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Book Income	112,577,867.17	62,544,835.00	175,122,702.17	36,775,767.46	8,192,064.88	44,967,832.34
Tax Items	14,725.71		14,725.71			
Book Income Before Tax	112,592,592.88	62,544,835.00	175,137,427.88	36,778,859.85	8,192,753.74	44,971,613.59
==						
EXCESS TAX vs BOOK DEPRECIATION						
230A ACRS BENEFIT NORMALIZED	7,644,000.00	(8,351,000.00)	(707,000.00)	(148,470.00)	(33,072.75)	(181,542.75)
280A EXCESS TX VS S/L BK DEPR	3,780,000.00	2,920,000.00	6,700,000.00	1,407,000.00	313,419.30	1,720,419.30
280H BK PLANT IN SERVICE - SFAS 143 - ARO	(23,154,213.88)	1,011,000.00	(22,143,213.88)	(4,650,074.91)	(1,035,837.40)	(5,685,912.31)
295A GAIN/LOSS ON ACRS/MACRS PROPERTY	-		-	-	-	-
390A CIAC - BOOK RECEIPTS	1,261,037.94	1,123,000.00	2,384,037.94	500,647.97	111,522.91	612,170.88
Total EXCESS TAX vs BOOK DEPRECIATION	(10,469,175.94)	(3,297,000.00)	(13,766,175.94)	(2,890,896.94)	(643,967.94)	(3,534,864.88)
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AFUDC / INTEREST CAPITALIZED						
320A ABFUDC	(3,242,825.59)	(2,979,000.00)	(6,221,825.59)	(1,306,583.37)	(291,050.78)	(1,597,634.15)
380J INT EXP CAPITALIZED FOR TAX	4,849,619.62	2,694,000.00	7,543,619.62	1,584,160.12	352,882.98	1,937,043.10
Total AFUDC / INTEREST CAPITALIZED	1,606,794.03	(285,000.00)	1,321,794.03	277,576.75	61,832.20	339,408.95
==						
PERCENT REPAIR ALLOWANCE						
532C BOOK/TAX UNIT OF PROPERTY ADJ	(31,549,000.00)	(32,441,000.00)	(63,990,000.00)	(13,437,900.00)	(2,993,388.21)	(16,431,288.21)
532D BOOK/TAX UNIT OF PROPERTY ADJ-SEC 481 ADJ	3,353,000.00	117,000.00	3,470,000.00	728,700.00	162,323.13	891,023.13
534A CAPITALIZED RELOCATION COSTS	(1,988,000.00)	(1,420,000.00)	(3,408,000.00)	(715,680.00)	(159,422.83)	(875,102.83)
Total PERCENT REPAIR ALLOWANCE	(30,184,000.00)	(33,744,000.00)	(63,928,000.00)	(13,424,880.00)	(2,990,487.91)	(16,415,367.91)
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REMOVAL COSTS						
910K REMOVAL CST	(12,401,000.00)	(8,804,000.00)	(21,205,000.00)	(4,453,050.00)	(991,948.70)	(5,444,998.70)
Total REMOVAL COSTS	(12,401,000.00)	(8,804,000.00)	(21,205,000.00)	(4,453,050.00)	(991,948.70)	(5,444,998.70)
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ACCELERATED AMORTIZATION						
533A TX AMORTIZATION POLLUTION CONTROL EQPT	(2,877,000.00)		(2,877,000.00)	(604,170.00)	(134,583.18)	(738,753.18)
533J TX ACCEL AMORT-CAPITALIZED SOFTWARE	(483,000.00)		(483,000.00)	(101,430.00)	(22,594.26)	(124,024.26)
Total ACCELERATED AMORTIZATION	(3,360,000.00)	-	(3,360,000.00)	(705,600.00)	(157,177.44)	(862,777.44)
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MINE DEVELOPMENT						
921A BK DEPLETION-MINERALS & RIGHTS	1,006,997.38	(6,399,000.00)	(5,392,002.62)	(1,132,320.55)	(252,232.49)	(1,384,553.04)
921G ACCEL BOOK DEPLETION	(8,400,000.00)	(6,792,000.00)	(15,192,000.00)	(3,190,320.00)	(710,666.57)	(3,900,986.57)
Total MINE DEVELOPMENT	(7,393,002.62)	(13,191,000.00)	(20,584,002.62)	(4,322,640.55)	(962,899.06)	(5,285,539.61)
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REVENUE REFUNDS						
520A PROVS POSS REV REFDS	1,611,191.29		1,611,191.29	338,350.17	75,369.92	413,720.09
520X PROV FOR RATE REFUND-TAX REFORM	29,008,073.17		29,008,073.17	6,091,695.37	1,356,968.65	7,448,664.02
520Y PROV FOR RATE REFUND-EXCESS PROTECTED	8,184,184.92		8,184,184.92	1,718,678.83	382,847.99	2,101,526.82
Total REVENUE REFUNDS	38,803,449.38	-	38,803,449.38	338,350.17	75,369.92	413,720.09
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DEFERRED FUEL COSTS						
433C AR - FUEL OVER/UNDER RECOVERY	(1,966,281.83)	16,349,000.00	14,382,718.17	3,020,370.82	672,809.17	3,693,179.99
433D LA - FUEL OVER/UNDER RECOVERY	(3,227.00)	-	(3,227.00)	(677.67)	(150.96)	(828.63)
Total DEFERRED FUEL COSTS	(1,969,508.83)	16,349,000.00	14,379,491.17	3,019,693.15	672,658.21	3,692,351.36
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Southwestern Electric Power Company **WP C-12-4**
Calculation of Income Tax Expense - Operating Income Adj for Factoring
Test Year Ending December 31, 2018
Docket No. 19-008-U

Effective State Tax Ra 0.046779

For the Period: Jan 2018 thru Jul 2018 Actual, Aug-Dec Forecasted	**January - July 2018**	**Forecasted Aug - December 2018**	**7 Months Actual Plus 5 Months Forecasted 2008**	**Federal Tax Effect**	**(AR, OK, LA, NE) State Tax Effect (4.6779%)**	**Total Tax Effect (25.6779%)**
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BOOK ACCRUALS						
602A PROV WORKER'S COMP	303,756.72		303,756.72	63,788.91	14,209.44	77,998.35
605B ACCRUED BK PENSION EXPENSE	3,941,213.58	2,169,000.00	6,110,213.58	1,283,144.85	285,829.68	1,568,974.53
605C ACCRUED BK PENSION COSTS - SFAS 158	(2,505,367.50)		(2,505,367.50)	(526,127.18)	(117,198.59)	(643,325.77)
605E SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN	50,236.68		50,236.68	10,549.70	2,350.02	12,899.72
605F ACCRD SUP EXEC RETIR PLAN COSTS-SFAS 158	(28,785.50)		(28,785.50)	(6,044.96)	(1,346.56)	(7,391.52)
605I ACCRD BK SUP. SAVINGS PLAN EXP	(99,160.73)		(99,160.73)	(20,823.75)	(4,638.64)	(25,462.39)
605K ACCRUED BK BENEFIT COSTS	(12,972.41)		(12,972.41)	(2,724.21)	(606.84)	(3,331.05)
605O ACCRUED PSI PLAN EXP	(2,200,062.36)		(2,200,062.36)	(462,013.10)	(102,916.72)	(564,929.82)
610A BK PROV UNCOLL ACCTS	(771,733.19)		(771,733.19)	(162,063.97)	(36,100.91)	(198,164.88)
611E ACCRUED MINE RECLAMATION	730,553.83		730,553.83	153,416.30	34,174.58	187,590.88
612Y ACCRD COMPANYWIDE INCENTV PLAN	(1,511,902.00)	2,736,000.00	1,224,098.00	257,060.58	57,262.08	314,322.66
613E ACCRUED BOOK VACATION PAY	791,254.18		791,254.18	166,163.38	37,014.08	203,177.46
613K (ICDP) - INCENTIVE COMP DEFERRAL PLAN	23,454.61		23,454.61	4,925.47	1,097.18	6,022.65
615B ACCRUED INTEREST-LONG-TERM - FIN 48	107,036.00	-	107,036.00	22,477.56	5,007.04	27,484.60
615C ACCRUED INTEREST-SHORT-TERM - FIN 48	4,798.00		4,798.00	1,007.58	224.45	1,232.03
Total BOOK ACCRUALS	(1,177,680.09)	4,905,000.00	3,727,319.91	782,737.16	174,360.29	957,097.45
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BOOK DEFERRALS						
615O BK DFL RAIL TRANS REV/EXP	(141.35)		(141.35)	(29.68)	(6.61)	(36.29)
630M RATE CASE DEFD CHGS	1,664,837.77		1,664,837.77	349,615.93	77,879.45	427,495.38
641I ADVANCE RENTAL INC (CUR MO)	1,131,640.20	(625,000.00)	506,640.20	106,394.44	23,700.12	130,094.56
660F REG ASSET - SFAS 143 - ARO	(779,208.67)		(779,208.67)	(163,633.82)	(36,450.60)	(200,084.42)
661R REG ASSET - SFAS 158 - PENSIONS	2,505,367.50		2,505,367.50	526,127.18	117,198.59	643,325.77
661S REG ASSET - SFAS 158 - SERP	28,785.50		28,785.50	6,044.96	1,346.56	7,391.52
661T REG ASSET - SFAS 158 - OPEB	(1,412,367.46)		(1,412,367.46)	(296,597.17)	(66,069.14)	(362,666.31)
664A REG ASSET-UND/REC ENVIRON ADJ CLAUSE-LA	80,107.60		80,107.60	16,822.60	3,747.35	20,569.95
664R REG ASSET-VALLEY DISTRICT DUE DILIGENCE	33,032.03		33,032.03	6,936.73	1,545.21	8,481.94
664V REG ASSET-NET CCS FEED STUDY COSTS	23,215.80		23,215.80	4,875.32	1,086.01	5,961.33
668P REG ASSET-LA FRP ASSET	54,954.54		54,954.54	11,540.45	2,570.72	14,111.17
669J REG ASSET-ENERGY EFFICIENCY RECOVERY	1,782,932.41	1,360,000.00	3,142,932.41	660,015.81	147,023.24	807,039.05
669X REG ASSET-SWEPCO SHIPE ROAD	816,100.65		816,100.65	171,381.14	38,176.37	209,557.51
669Y REG ASSET-2010 SEVERANCE COSTS-LA FRP	269,940.70		269,940.70	56,687.55	12,627.56	69,315.11
670O REG ASSET-ENVIRONMENTAL CHEMICAL COST-AR	(588,182.20)		(588,182.20)	(123,518.26)	(27,514.58)	(151,032.84)
672P REG ASSET-FACILITIES MAINT-SWEPCO LA	(114,086.29)		(114,086.29)	(23,958.12)	(5,336.84)	(29,294.96)
673J REG ASSET-WELSH/FLINT CRK ENVIRON DEF	958,655.74	209,000.00	1,167,655.74	245,207.71	54,621.77	299,829.48
673K REG ASSET-WELSH/FLINT CRK ENVIRON-CONTRA	(335,310.64)		(335,310.64)	(70,415.23)	(15,685.50)	(86,100.73)
673U REG ASSET-LA 2015 FRP-SPP DEFERRAL	(375,078.66)	1,316,000.00	940,921.34	197,593.48	44,015.36	241,608.84
673V REG ASSET-LA 2015 FRP-UNREC EQUITY	175,253.45		175,253.45	36,803.22	8,198.18	45,001.40
673Z REG ASSET-WELSH 2 TX-UNDEPR BAL	284,097.46		284,097.46	59,660.47	13,289.80	72,950.27
Total BOOK DEFERRALS	6,204,546.08	2,260,000.00	8,464,546.08	1,777,554.71	395,963.02	2,173,517.73
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BOOK RESERVES						
651F DISALLOWED COSTS-TURK PLANT	(633,078.53)	(737,000.00)	(1,370,078.53)	(287,716.49)	(64,090.90)	(351,807.39)
651H DISALLOWED COSTS-TURK PLANT AUX BOILER	(220,150.00)		(220,150.00)	(46,231.50)	(10,298.40)	(56,529.90)
651I DISALLOWED COSTS-TX TRANS VEG MGT CST	246,212.07		246,212.07	51,704.53	11,517.55	63,222.08
651J DISALLOWED COSTS-TX DIST VEG MGT CST	(24,276.23)		(24,276.23)	(5,098.01)	(1,135.62)	(6,233.63)
651K DISALLOWED COSTS-TX TRANS VEG MGT CST-AMORT	(13,870.09)		(13,870.09)	(2,912.72)	(648.83)	(3,561.55)
651M DISALLOWED COSTS-TX DIST VEG MGT CST-AMORT	(64,313.61)		(64,313.61)	(13,505.86)	(3,008.53)	(16,514.39)

Southwestern Electric Power Company **WP C-12-4**
Calculation of Income Tax Expense - Operating Income Adj for Factoring
Test Year Ending December 31, 2018
Docket No. 19-008-U

Effective State Tax Ra 0.046779

For the Period: Jan 2018 thru Jul 2018 Actual, Aug-Dec Forecasted	**January - July 2018**	**Forecasted Aug - December 2018**	**7 Months Actual Plus 5 Months Forecasted 2008**	**Federal Tax Effect**	**(AR, OK, LA, NE) State Tax Effect (4.6779%)**	**Total Tax Effect (25.6779%)**
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651Q DISALLOWED COSTS-TX SERP COSTS	(351,012.75)		(351,012.75)	(73,712.68)	(16,420.03)	(90,132.71)
651R DISALLOWED COSTS-TX DIST COSTS	(183,982.07)		(183,982.07)	(38,636.23)	(8,606.50)	(47,242.73)
651S DISALLOWED COSTS-TX GEN COSTS	(5,901,516.59)	(7,374,096.91)	(13,275,613.50)	(2,787,878.84)	(621,019.92)	(3,408,898.76)
651T DISALLOWED COSTS-TX CWIP FINBASED INCEN-TRANS	1,747,345.47		1,747,345.47	366,942.55	81,739.07	448,681.62
651W DISALLOWED COSTS-TX CWIP FINBASED INCEN-DIST	2,107,031.67	1,628,000.00	3,735,031.67	784,356.65	174,721.05	959,077.70
651X DISALLOWED COSTS-TX CWIP FINBASED INCEN-GEN	2,468,125.88	1,517,000.00	3,985,125.88	836,876.43	186,420.20	1,023,296.63
651Y DISALLOWED COSTS-TX RWIP FINBASED INCEN-TRANS	63,897.38		63,897.38	13,418.45	2,989.06	16,407.51
651Z DISALLOWED COSTS-TX RWIP FINBASED INCEN-DIST	84,668.54		84,668.54	17,780.39	3,960.71	21,741.10
653A DISALLOWED COSTS-TX RWIP FINBASED INCEN-GEN	94,091.98		94,091.98	19,759.32	4,401.53	24,160.85
Total BOOK RESERVES	(580,826.88)	(4,966,096.91)	(5,546,923.79)	(1,164,854.01)	(259,479.56)	(1,424,333.57)
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OTHER MISCELLANEOUS						
690F REG ASSET-NBV-ARO-RETIRED PLANTS	4,153.38		4,153.38	872.21	194.29	1,066.50
900A LOSS ON REACQUIRED DEBT	328,020.27	107,000.00	435,020.27	91,354.26	20,349.81	111,704.07
900F BK DEFL-GAIN REACQUIRED DEBT	(6,481.69)		(6,481.69)	(1,361.15)	(303.21)	(1,664.36)
906A ACCRD SFAS 106 PST RETIRE EXP	(3,379,341.65)	(3,025,000.00)	(6,404,341.65)	(1,344,911.75)	(299,588.70)	(1,644,500.45)
906F ACCRD OPEB COSTS - SFAS 158	1,412,367.46		1,412,367.46	296,597.17	66,069.14	362,666.31
906K ACCRD SFAS 112 PST EMPLOY BEN	707,942.00		707,942.00	148,667.82	33,116.82	181,784.64
906P ACCRD BOOK ARO EXPENSE - SFAS 143	21,170,807.56	-	21,170,807.56	4,445,869.59	990,349.21	5,436,218.80
906Z SFAS 106 - MEDICARE SUBSIDY - (PPACA)-REG ASSET	311,097.50		311,097.50	65,330.48	14,552.83	79,883.31
911S ACCRUED SALES & USE TAX RESERVE	(311,500.00)		(311,500.00)	(65,415.00)	(14,571.66)	(79,986.66)
914A SFAS 109 - DEFD SIT LIABILITY	1,860,387.00		1,860,387.00	390,681.27	87,027.04	477,708.31
914B REG ASSET - SFAS 109 DSIT LIAB	(1,860,387.00)		(1,860,387.00)	(390,681.27)	(87,027.04)	(477,708.31)
930A BOOK > TAX BASIS-PRTSHP INVEST	(840,000.00)		(840,000.00)	(176,400.00)	(39,294.36)	(215,694.36)
940X IRS CAPITALIZATION ADJUSTMENT	(225,012.00)		(225,012.00)	(47,252.52)	(10,525.84)	(57,778.36)
980A RESTRICTED STOCK PLAN	(208,192.70)		(208,192.70)	(43,720.47)	(9,739.05)	(53,459.52)
980J PSI-STOCK-BASED PLAN	191,609.08		191,609.08	40,237.91	8,963.28	49,201.19
Total OTHER MISCELLANEOUS	19,155,469.21	(2,918,000.00)	16,237,469.21	3,409,868.55	759,572.56	4,169,441.11
=======================================						
PERMANENT SCHEDULE M's						
910B NON-DEDUCT MEALS AND T&E	225,188.20	393,000.00	618,188.20	129,819.52	28,918.23	158,737.75
910E NON-DEDUCT - MISCELLANEOUS	(120,028.87)		(120,028.87)	(25,206.06)	(5,614.83)	(30,820.89)
980B RESTRICTED STOCK PLAN-TAX DEDUCTION	(74,558.55)		(74,558.55)	(15,657.30)	(3,487.77)	(19,145.07)
Total PERMANENT SCHEDULE M's	30,600.78	393,000.00	423,600.78	88,956.16	19,815.63	108,771.79
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TAX ACCRUALS						
711O BOOK LEASES CAPITALIZED FOR TAX	2,128,000.00		2,128,000.00	446,880.00	99,545.71	546,425.71
Total TAX ACCRUALS	2,128,000.00	-	2,128,000.00	446,880.00	99,545.71	546,425.71
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TAX DEFERRALS						
702A GOODWILL PER TAX	(235,522.00)	(168,000.00)	(403,522.00)	(84,739.62)	(18,876.36)	(103,615.98)
710H AMORT ELEC PLT ACQ ADJS	(35,623.00)	-	(35,623.00)	(7,480.83)	(1,666.41)	(9,147.24)
712K CAPITALIZED SOFTWARE COST-BOOK	(2,349,586.71)		(2,349,586.71)	(493,413.21)	(109,911.32)	(603,324.53)
Total TAX DEFERRALS	(2,620,731.71)	(168,000.00)	(2,788,731.71)	(585,633.66)	(130,454.09)	(716,087.75)
=======================================						
MARK-TO-MARKET ADJUSTMENTS						
575C MTM BK LOSS-B/L TAX DEFL	3,769,875.00		3,769,875.00	791,673.75	176,350.98	968,024.73
610V PROV-FAS 157 - A/L	(15,837.00)		(15,837.00)	(3,325.77)	(740.84)	(4,066.61)
652G REG LIAB-UNREAL MTM GAIN-DEFL	(3,754,037.38)		(3,754,037.38)	(788,347.85)	(175,610.11)	(963,957.96)

Southwestern Electric Power Company **WP C-12-4**
Calculation of Income Tax Expense - Operating Income Adj for Factoring
Test Year Ending December 31, 2018
Docket No. 19-008-U

Effective State Tax Ra 0.046779

For the Period: Jan 2018 thru Jul 2018 Actual, Aug-Dec Forecasted	January - July 2018	Forecasted Aug - December 2018	7 Months Actual Plus 5 Months Forecasted 2008	Federal Tax Effect	(AR, OK, LA, NE) State Tax Effect (4.6779%)	Total Tax Effect (25.6779%)
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Total MARK-TO-MARKET ADJUSTMENTS	0.62	-	0.62	0.13	0.03	0.16
==						
EMISSION ALLOWANCES						
638A BOOK > TAX BASIS - EMA-A/C 283	64,078.00	100,000.00	164,078.00	34,456.38	7,675.40	42,131.78
Total EMISSION ALLOWANCES	64,078.00	100,000.00	164,078.00	34,456.38	7,675.40	42,131.78
==						
Total Book/Tax Income Differences	(2,162,987.97)	(43,366,096.91)	(45,529,084.88)	(17,371,482.00)	(3,869,621.73)	(21,241,103.73)
==						
Taxable Income Before State Tax	110,429,604.91	19,178,738.09	129,608,343.00	27,217,752.03	6,062,948.68	33,280,700.71
State and Local Current Tax	3,840,773.51	-	3,840,773.51	806,562.44	(2,222,175.17)	(3,028,737.61)
Federal Taxable Income	106,588,831.40	19,178,738.09	125,767,569.49	26,411,189.59		30,251,963.10
Statutory Rate	21%	21%	21%			
Current Federal Tax Before Credits and Adjustments	22,383,655.00	4,027,535.00	26,411,190.00	26,411,189.59		30,251,963.10
Credits	2,736,576.33		2,736,576.33	2,736,576.33		2,736,576.33
Current Federal Tax	19,647,078.67	4,027,535.00	23,674,613.67	23,674,613.26		27,515,386.77

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Southwestern Electric Power Company
Calculation of Deferred Income Tax Expense - Operating
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP C-12-5

For the Period: Jan 2018 thru Jul 2018 Actual, Aug-Dec Forecasted	Jan - Jul 2018	Forecasted Aug - Dec 2018	7 Months Actual Plus 5 Months Forecasted 2018	Adjustments (a) (b)	Adjusted Test Year 2019
==					
Book Income	112,577,867.17	62,544,835.00	175,122,702.17		175,122,702.17
Tax Items	14,725.71		14,725.71		14,725.71
Book Income Before Tax	112,592,592.88	62,544,835.00	175,137,427.88	-	175,137,427.88
==					
EXCESS TAX vs BOOK DEPRECIATION					
230A ACRS BENEFIT NORMALIZED	7,644,000.00	(8,351,000.00)	(707,000.00)	39,600,280.22	38,893,280.22
280A EXCESS TX VS S/L BK DEPR	3,780,000.00	2,920,000.00	6,700,000.00	(618,095.12)	6,081,904.88
280H BK PLANT IN SERVICE - SFAS 143 - ARO	(23,154,213.88)	1,011,000.00	(22,143,213.88)		(22,143,213.88)
295A GAIN/LOSS ON ACRS/MACRS PROPERTY	-		-		-
390A CIAC - BOOK RECEIPTS	1,261,037.94	1,123,000.00	2,384,037.94		2,384,037.94
Total EXCESS TAX vs BOOK DEPRECIATION	(10,469,175.94)	(3,297,000.00)	(13,766,175.94)	38,982,185.10	25,216,009.16
==					
AFUDC / INTEREST CAPITALIZED					
310E AOFUDC-BIP AMORT-ALL PROJECTS	-	-	-		-
320A ABFUDC	(3,242,825.59)	(2,979,000.00)	(6,221,825.59)		(6,221,825.59)
380J INT EXP CAPITALIZED FOR TAX	4,849,619.62	2,694,000.00	7,543,619.62		7,543,619.62
Total AFUDC / INTEREST CAPITALIZED	1,606,794.03	(285,000.00)	1,321,794.03	-	1,321,794.03
==					
PERCENT REPAIR ALLOWANCE					
532C BOOK/TAX UNIT OF PROPERTY ADJ	(31,549,000.00)	(32,441,000.00)	(63,990,000.00)		(63,990,000.00)
532D BOOK/TAX UNIT OF PROPERTY ADJ-SEC 481 ADJ	3,353,000.00	117,000.00	3,470,000.00		3,470,000.00
534A CAPITALIZED RELOCATION COSTS	(1,988,000.00)	(1,420,000.00)	(3,408,000.00)		(3,408,000.00)
Total PERCENT REPAIR ALLOWANCE	(30,184,000.00)	(33,744,000.00)	(63,928,000.00)	-	(63,928,000.00)
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REMOVAL COSTS					
910K REMOVAL CST	(12,401,000.00)	(8,804,000.00)	(21,205,000.00)		(21,205,000.00)
910W REMOVAL COSTS REV-SFAS 143-ARO	-		-	-	-
Total REMOVAL COSTS	(12,401,000.00)	(8,804,000.00)	(21,205,000.00)	-	(21,205,000.00)
==					
ACCELERATED AMORTIZATION					
533A TX AMORTIZATION POLLUTION CONTROL EQPT	(2,877,000.00)		(2,877,000.00)	2,877,000.00	-
533J TX ACCEL AMORT-CAPITALIZED SOFTWARE	(483,000.00)		(483,000.00)	483,000.00	-
Total ACCELERATED AMORTIZATION	(3,360,000.00)	-	(3,360,000.00)	3,360,000.00	-
==					
MINE DEVELOPMENT					
921A BK DEPLETION-MINERALS & RIGHTS	1,006,997.38	(6,399,000.00)	(5,392,002.62)		(5,392,002.62)
921G ACCEL BOOK DEPLETION	(8,400,000.00)	(6,792,000.00)	(15,192,000.00)	(408,000.00)	(15,600,000.00)
Total MINE DEVELOPMENT	(7,393,002.62)	(13,191,000.00)	(20,584,002.62)	(408,000.00)	(20,992,002.62)
==					
REVENUE REFUNDS					
520A PROVS POSS REV REFDS	1,611,191.29		1,611,191.29	(1,611,191.29)	-
520X PROV FOR RATE REFUND-TAX REFORM	29,008,073.17		29,008,073.17	(29,008,073.17)	
520Y PROV FOR RATE REFUND-EXCESS PROTECTED	8,184,184.92		8,184,184.92	(8,184,184.92)	
Total REVENUE REFUNDS	38,803,449.38	-	38,803,449.38	(38,803,449.38)	-
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DEFERRED FUEL COSTS					
433C AR - FUEL OVER/UNDER RECOVERY	(1,966,281.83)	16,349,000.00	14,382,718.17	(14,382,718.17)	-
433D LA - FUEL OVER/UNDER RECOVERY	(3,227.00)	-	(3,227.00)	3,227.00	-
Total DEFERRED FUEL COSTS	(1,969,508.83)	16,349,000.00	14,379,491.17	(14,379,491.17)	-
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BOOK ACCRUALS					
602A PROV WORKER'S COMP	303,756.72		303,756.72		303,756.72
605B ACCRUED BK PENSION EXPENSE	3,941,213.58	2,169,000.00	6,110,213.58		6,110,213.58
605C ACCRUED BK PENSION COSTS - SFAS 158	(2,505,367.50)		(2,505,367.50)	2,505,367.50	-
605E SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN	50,236.68		50,236.68		50,236.68
605F ACCRD SUP EXEC RETIR PLAN COSTS-SFAS 158	(28,785.50)		(28,785.50)	28,785.50	-
605I ACCRD BK SUP. SAVINGS PLAN EXP	(99,160.73)		(99,160.73)		(99,160.73)
605K ACCRUED BK BENEFIT COSTS	(12,972.41)		(12,972.41)		(12,972.41)
605O ACCRUED PSI PLAN EXP	(2,200,062.36)		(2,200,062.36)		(2,200,062.36)
610A BK PROV UNCOLL ACCTS	(771,733.19)		(771,733.19)		(771,733.19)
611E ACCRUED MINE RECLAMATION	730,553.83		730,553.83	(730,553.83)	-
612Y ACCRD COMPANYWIDE INCENTV PLAN	(1,511,902.00)	2,736,000.00	1,224,098.00		1,224,098.00
613E ACCRUED BOOK VACATION PAY	791,254.18		791,254.18		791,254.18
613K (ICDP) - INCENTIVE COMP DEFERRAL PLAN	23,454.61		23,454.61		23,454.61
615B ACCRUED INTEREST-LONG-TERM - FIN 48	107,036.00	-	107,036.00	(107,036.00)	-
615C ACCRUED INTEREST-SHORT-TERM - FIN 48	4,798.00		4,798.00	(4,798.00)	-
Total BOOK ACCRUALS	(1,177,680.09)	4,905,000.00	3,727,319.91	1,691,765.17	5,419,085.08
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BOOK DEFERRALS					
615O BK DFL RAIL TRANS REV/EXP	(141.35)		(141.35)	141.35	-
630M RATE CASE DEFD CHGS	1,664,837.77		1,664,837.77	(1,664,837.77)	-
641I ADVANCE RENTAL INC (CUR MO)	1,131,640.20	(625,000.00)	506,640.20		506,640.20

Southwestern Electric Power Company **WP C-12-5**
Calculation of Deferred Income Tax Expense - Operating
Test Year Ending December 31, 2018
Docket No. 19-008-U

For the Period: Jan 2018 thru Jul 2018 Actual, Aug-Dec Forecasted	Jan - Jul 2018	Forecasted Aug - Dec 2018	7 Months Actual Plus 5 Months Forecasted 2018	Adjustments (a) (b)	Adjusted Test Year 2019
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660F REG ASSET - SFAS 143 - ARO	(779,208.67)		(779,208.67)		(779,208.67)
661R REG ASSET - SFAS 158 - PENSIONS	2,505,367.50		2,505,367.50	(2,505,367.50)	-
661S REG ASSET - SFAS 158 - SERP	28,785.50		28,785.50	(28,785.50)	-
661T REG ASSET - SFAS 158 - OPEB	(1,412,367.46)		(1,412,367.46)	1,412,367.46	-
664A REG ASSET-UND/REC ENVIRON ADJ CLAUSE-LA	80,107.60		80,107.60	(80,107.60)	-
664R REG ASSET-VALLEY DISTRICT DUE DILIGENCE	33,032.03		33,032.03	(33,032.03)	-
664V REG ASSET-NET CCS FEED STUDY COSTS	23,215.80		23,215.80		23,215.80
668P REG ASSET-LA FRP ASSET	54,954.54		54,954.54	(54,954.54)	-
669J REG ASSET-ENERGY EFFICIENCY RECOVERY	1,782,932.41	1,360,000.00	3,142,932.41	(3,142,932.41)	-
669X REG ASSET-SWEPCO SHIPE ROAD	816,100.65		816,100.65	(816,100.65)	-
669Y REG ASSET-2010 SEVERANCE COSTS-LA FRP	269,940.70		269,940.70	(269,940.70)	-
670O REG ASSET-ENVIRONMENTAL CHEMICAL COST-AR	(588,182.20)		(588,182.20)	588,182.20	-
672P REG ASSET-FACILITIES MAINT-SWEPCO LA	(114,086.29)		(114,086.29)	114,086.29	-
673J REG ASSET-WELSH/FLINT CRK ENVIRON DEF	958,655.74	209,000.00	1,167,655.74	(1,167,655.74)	-
673K REG ASSET-WELSH/FLINT CRK ENVIRON-CONTRA	(335,310.64)		(335,310.64)	335,310.64	-
673U REG ASSET-LA 2015 FRP-SPP DEFERRAL	(375,078.66)	1,316,000.00	940,921.34	(940,921.34)	-
673V REG ASSET-LA 2015 FRP-UNREC EQUITY	175,253.45		175,253.45	(175,253.45)	-
673Z REG ASSET-WELSH 2 TX-UNDEPR BAL	284,097.46		284,097.46	(284,097.46)	-
Total BOOK DEFERRALS	6,204,546.08	2,260,000.00	8,464,546.08	(8,713,898.75)	(249,352.67)
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BOOK RESERVES					
651F DISALLOWED COSTS-TURK PLANT	(633,078.53)	(737,000.00)	(1,370,078.53)	1,370,078.53	-
651H DISALLOWED COSTS-TURK PLANT AUX BOILER	(220,150.00)		(220,150.00)	220,150.00	-
651I DISALLOWED COSTS-TX TRANS VEG MGT CST	246,212.07		246,212.07	(246,212.07)	-
651J DISALLOWED COSTS-TX DIST VEG MGT CST	(24,276.23)		(24,276.23)	24,276.23	-
651K DISALLOWED COSTS-TX TRANS VEG MGT CST-AMORT	(13,870.09)		(13,870.09)	13,870.09	-
651M DISALLOWED COSTS-TX DIST VEG MGT CST-AMORT	(64,313.61)		(64,313.61)	64,313.61	-
651Q DISALLOWED COSTS-TX SERP COSTS	(351,012.75)		(351,012.75)	351,012.75	-
651R DISALLOWED COSTS-TX DIST COSTS	(183,982.07)		(183,982.07)	183,982.07	-
651S DISALLOWED COSTS-TX GEN COSTS	(5,901,516.59)	(7,374,096.91)	(13,275,613.50)	13,275,613.50	-
651T DISALLOWED COSTS-TX CWIP FINBASED INCEN-TRANS	1,747,345.47		1,747,345.47	(1,747,345.47)	-
651W DISALLOWED COSTS-TX CWIP FINBASED INCEN-DIST	2,107,031.67	1,628,000.00	3,735,031.67	(3,735,031.67)	-
651X DISALLOWED COSTS-TX CWIP FINBASED INCEN-GEN	2,468,125.88	1,517,000.00	3,985,125.88	(3,985,125.88)	-
651Y DISALLOWED COSTS-TX RWIP FINBASED INCEN-TRANS	63,897.38		63,897.38	(63,897.38)	-
651Z DISALLOWED COSTS-TX RWIP FINBASED INCEN-DIST	84,668.54		84,668.54	(84,668.54)	-
653A DISALLOWED COSTS-TX RWIP FINBASED INCEN-GEN	94,091.98		94,091.98	(94,091.98)	-
=======================================	(580,826.88)	(4,966,096.91)	(5,546,923.79)	5,546,923.79	-
OTHER MISCELLANEOUS					
690F REG ASSET-NBV-ARO-RETIRED PLANTS	4,153.38		4,153.38		4,153.38
900A LOSS ON REACQUIRED DEBT	328,020.27	107,000.00	435,020.27		435,020.27
900F BK DEFL-GAIN REACQUIRED DEBT	(6,481.69)		(6,481.69)		(6,481.69)
906A ACCRD SFAS 106 PST RETIRE EXP	(3,379,341.65)	(3,025,000.00)	(6,404,341.65)		(6,404,341.65)
906F ACCRD OPEB COSTS - SFAS 158	1,412,367.46		1,412,367.46	(1,412,367.46)	-
906K ACCRD SFAS 112 PST EMPLOY BEN	707,942.00		707,942.00		707,942.00
906P ACCRD BOOK ARO EXPENSE - SFAS 143	21,170,807.56	-	21,170,807.56		21,170,807.56
906Z SFAS 106 - MEDICARE SUBSIDY - (PPACA)-REG ASSET	311,097.50		311,097.50		
911S ACCRUED SALES & USE TAX RESERVE	(311,500.00)		(311,500.00)	311,500.00	-
914A SFAS 109 - DEFD SIT LIABILITY	1,860,387.00		1,860,387.00		1,860,387.00
914B REG ASSET - SFAS 109 DSIT LIAB	(1,860,387.00)		(1,860,387.00)		(1,860,387.00)
930A BOOK > TAX BASIS-PRTSHP INVEST	(840,000.00)		(840,000.00)		(840,000.00)
940X IRS CAPITALIZATION ADJUSTMENT	(225,012.00)		(225,012.00)		
980A RESTRICTED STOCK PLAN	(208,192.70)		(208,192.70)		
980J PSI-STOCK-BASED PLAN	191,609.08		191,609.08		
Total OTHER MISCELLANEOUS	19,155,469.21	(2,918,000.00)	16,237,469.21	(1,100,867.46)	15,067,099.87
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PERMANENT SCHEDULE M's					
910B NON-DEDUCT MEALS AND T&E	225,188.20	393,000.00	618,188.20		618,188.20
910E NON-DEDUCT - MISCELLANEOUS	(120,028.87)		(120,028.87)		(120,028.87)
980B RESTRICTED STOCK PLAN-TAX DEDUCTION	(74,558.55)		(74,558.55)		(74,558.55)
Total PERMANENT SCHEDULE M's	30,600.78	393,000.00	423,600.78	-	423,600.78
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TAX ACCRUALS					
711O BOOK LEASES CAPITALIZED FOR TAX	2,128,000.00		2,128,000.00		2,128,000.00
Total TAX ACCRUALS	2,128,000.00	-	2,128,000.00	-	2,128,000.00
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TAX DEFERRALS					
702A GOODWILL PER TAX	(235,522.00)	(168,000.00)	(403,522.00)	403,522.00	-
710H AMORT ELEC PLT ACQ ADJS	(35,623.00)	-	(35,623.00)		(35,623.00)
712K CAPITALIZED SOFTWARE COST-BOOK	(2,349,586.71)		(2,349,586.71)	(7,584,352.00)	(9,933,938.71)
Total TAX DEFERRALS	(2,620,731.71)	(168,000.00)	(2,788,731.71)	(7,180,830.00)	(9,969,561.71)
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MARK-TO-MARKET ADJUSTMENTS					
575E MTM BK GAIN-A/L-TAX DEFL	3,769,875.00		3,769,875.00	(3,769,875.00)	-

Southwestern Electric Power Company
Calculation of Deferred Income Tax Expense - Operating
Test Year Ending December 31, 2018
Docket No. 19-008-U

For the Period: Jan 2018 thru Jul 2018 Actual, Aug-Dec Forecasted	Jan - Jul 2018	Forecasted Aug - Dec 2018	7 Months Actual Plus 5 Months Forecasted 2018	Adjustments (a) (b)	Adjusted Test Year 2019
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610V PROV-FAS 157 - A/L	(15,837.00)		(15,837.00)	15,837.00	-
652G REG LIAB-UNREAL MTM GAIN-DEFL	(3,754,037.38)		(3,754,037.38)	3,754,037.38	-
Total MARK-TO-MARKET ADJUSTMENTS	0.62	-	0.62	(0.62)	-
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EMISSION ALLOWANCES					
638A BOOK > TAX BASIS - EMA-A/C 283	64,078.00	100,000.00	164,078.00	(164,078.00)	-
Total EMISSION ALLOWANCES	64,078.00	100,000.00	164,078.00	(164,078.00)	-
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Total Book/Tax Income Differences	(2,162,987.97)	(43,366,096.91)	(45,529,084.88)	(21,169,741.32)	(66,768,328.08)
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Taxable Income Before State Tax	110,429,604.91	19,178,738.09	129,608,343.00	(21,169,741.32)	108,438,601.68
State and Local Current Tax	3,840,773.51	-	3,840,773.51	(706,863.51)	3,133,910.00
Federal Taxable Income	106,588,831.40	19,178,738.09	125,767,569.49	(20,462,877.81)	105,304,691.68
Statutory Rate	21%	21%	21%	21%	21%
Current Federal Tax Before Credits and Adjustments	22,383,655.00	4,027,535.00	26,411,190.00	(4,297,204.00)	22,113,986.00
Credits	3,542,824.82	(44,818.00)	3,498,006.82	(3,498,006.82)	-
Current Federal Tax	18,840,830.18	4,072,353.00	22,913,183.18	(799,197.18)	22,113,986.00

Note: Operating schedule only to show 2019 Adjusted Tax Year

Supporting Schedules
(a) WP F-1.3
(b) WP B 2-9

Southwestern Electric Power Company
Index-D Workpapers
Test Year Ending December 31, 2018
Docket No. 19-008-U

Workpaper	Description
Schedule D-1.2	Cost of Capital Projected Test Year
Schedule D-1.3	Cost of Capital Pro Forma Year
WP D-1-1	Current, Accrued and Other Liabilities Balance
WP D-1-2	Analysis and Calculation of Customer Deposit Interest
WP D-1-3	Money Pool Interest Rate Calculation
WP D-1-4	Common Equity Reconciliation
WP D-1-5	Adjusted Weighted Cost of Debt - Support
WP D-1-6	Other Capital Items
Schedule D-2.1	Cost of Long Term Debt - Per Books Test Year
Schedule D-2.2	Cost of Long Term Debt - Projected Test Year
Schedule D-2.3	Cost of Long Term Debt - Pro Forma Year
WP D-2-1	Adjusted Weighted Cost of Debt - Support
Schedule D-3.2	Cost of Preferred Stock- Projected Test Year
Schedule D-4	Cost of Common Equity
Schedule D-5.1	Cost of Other Capital Items- Per Books Test Year
Schedule D-5.2	Cost of Other Capital Items- Projected Test Year
Schedule D-5.3	Cost of Other Capital Items- Pro Forma Year
Schedule D-6.1	Calculation of Current, Accrued and Other Liabilities
WP D-6.1	Adjustment to Working Capital Liabilities to Remove Turk Plant
WP D-6.1-1	Turk Plant Liability Adjustment Support
Schedule D-6.2	Liability Account Balances
Schedule D-6.3	Interest Bearing Liabilities' Expense Information
WP D-6.3	Misc. Interest Expense Support
Schedule D-7	Advances for Construction and Contributions in Aid of Construction

Southwestern Electric Power Company
Cost of Capital Projected Test Year
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE D-1.2

Explanation: Schedule showing elements of actual total company capital structure and the related costs at the end of the projected test year. Schedule D-1.2 should only be completed if the company is filing a partially projected test year.

Line No.	(1) Description		(2) Amount Per Books July 2018 (f)	(3) Adjustments for Projected Portion of Test Year	(4) Amount Projected Test Year (A) December 2018	(5) Rate %(f)
			Projected Test Year as of 12/31/2018			
1	Long Term Debt	(a), (c)	2,419,977,304	$ (520,166,899)	1,899,810,405.32	4.22%
2	Common Equity	(a)	2,275,413,723	$ (334,716,701)	1,940,697,022	10.50%
3	Accumulated Deferred Income Taxes	(a), (d)	911,071,417	(237,015,033)	674,056,384	0.00%
4	ADITC - Debt	(a)	3,088,198	(252,310)	2,835,887	4.22%
5	ADITC - Equity		1,956,738	(159,868)	1,796,870	10.50%
6	ADITC - Short Term Debt		31,691	(2,589)	29,102	2.75%
7	Short Term/Interim Debt	(a)	106,690,962	(98,075,822)	8,615,140	2.75%
8	Customer Deposits	(a)	63,929,187	-	63,929,187	2.92%
9	Current, Accrued and Other Liabilities	(b)	1,362,890,803	(52,683,019)	1,310,207,784	0.00%
10	Other Capital Items	(b), (e)	207,042,962	(37,257,309)	169,785,653	3.82%
11	Totals	(f)	**$ 7,352,092,986**	**$ (1,280,329,551)**	**$ 6,071,763,434**	

Supporting Schedules and Workpapers:

(a) Schedule E-1, E-17
(b) WP D-1-1
(c) Schedule D-2.2
(d) WP C-10-4, C-10-5. C-10
(e) WP D-1-6
(f) Schedule D-2.2, WP D-1-3, WP D-1-2, WP D-1-6

Recap Schedules:

(A) Schedule D-1.3

Southwestern Electric Power Company
Cost of Capital Pro Forma Year
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE D-1.3

Explanation: Schedule showing elements of actual total company capital structure and the related costs at the end of the pro forma year.

Line No.	(1) Description	Pro Forma Year as of 12/31/2019 (2) Amount Beginning of Pro Forma Year (a)	(3) Pro Forma Adjustments	(4) Amount End of Pro Forma Year		(5) Proportion (Amount/Total)	(6) Rate % (b)	(7) Weighted Cost % (Col.6 x Col.7)
1	Long Term Debt	$ 1,899,810,405	$ 95,680,815	1,995,491,220	(c)	33.63%	4.28%	1.4412%
2	Common Equity	1,940,697,022	93,529,494	2,034,226,516	(d)	34.29%	10.50%	3.6001%
3	Accumulated Deferred Income Taxes	674,056,384	(22,986,276)	651,070,108	(e)	10.97%	0.00%	0.0000%
4	ADITC - Debt	2,835,887	(235,271)	2,600,616	(f)	0.04%	4.28%	0.0019%
5	ADITC - Equity	1,796,870	(149,072)	1,647,798	(f)	0.03%	10.50%	0.0029%
6	ADITC - Short Term Debt	29,102	(2,414)	26,688	(f)	0.00%	3.36%	0.0000%
7	Short Term/Interim Debt	8,615,140	24,331,180	32,946,320	(c)	0.56%	3.36%	0.0187%
8	Customer Deposits	63,929,187	-	63,929,187	(c)	1.08%	2.92%	0.0315%
9	Current, Accrued and Other Liabilities	1,310,207,784	(336,703,718)	973,504,066	(h)	16.41%	0.00%	0.0000%
10	Other Capital Items	169,785,653	7,782,407	177,568,060	(h)	2.99%	3.88%	0.1162%
11	Totals	$ 6,071,763,434	$ (138,752,854)	$ 5,933,010,580		100.00%	(A)	5.2125%

Supporting Schedules and Workpapers:
(a) Schedule D-1.2
(b) Rates must be adequately cross-referenced to applicable D schedules
(c) Schedule D-2.3
(d) WP D 1-4
(e) WP C-10-4, C-10-5, Schedule C-10
(f) Schedule C-9, WP D-1.5
(g) Schedule E-17
(h) WP D 1-1

Recap Schedules:
(A) Schedule A-1

Southwestern Electric Power Company
Current, Accrued and Other Liabilities Balance
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP D-1-1

Line No.	Description	Account	Ref.(a)	Balance at end of Historical period	Adjustments	Test Year 12/31/2018	Adjustments	Projected 12/31/2019
1	Current, Accrued and Other Liabilities		Schedule D-6.1	2,816,657,174		2,674,170,684		973,504,066
2	Less Amounts Shown Independently:							
3	Accumulated Income Taxes	281.1, 281.4, 282.1, 282.3, 283.3 & 283.4	Schedule E-17B	1,215,683,895		1,224,254,257		(1)
4	ADITC	255	Schedule E-17B	5,076,627		4,661,859		(1)
5	Short Term Interim Debt-Corp Borrow Program	233	Schedule D-6.1	106,690,962		8,615,140		(1)
6	Unamt Gain on Reacquired Debt	257	Schedule E-17B	13,529		13,529		(1)
7	Customer Deposits	235	Schedule D-6.1	63,929,187		63,929,187		(1)
8	Other Capital - A/P Assoc Co - Factored A/R	234	Schedule E-17B	55,428,382		55,428,382		(1)
9	Other Capital - IPP-System Upgrade Credits	253	Schedule D-6.1	6,943,788		7,060,546		(1)
10	Net Current, Accrued and Other Liabilities (A)			1,362,890,803		1,310,207,784		973,504,066
11	Other Capital Items - Interest Bearing:							
12	A/P Assoc Co - Factored A/R	234	Schedule E-17B	55,428,382	(7,958,480)	47,469,902		47,469,902
13	IPP-System Upgrade Credits	253	Schedule D-6.1	6,943,788	116,758	7,060,546	7,782,407	14,842,953
14	Plus Contra Asset Account							
15	Customer A/R - Factored	142	Schedule E-17B	144,670,792	(29,415,587)	115,255,205		115,255,205
16	Total Other Captial Items (A)			207,042,962		169,785,653		177,568,060

(1) Already removed from Current, Accrued and Other Liabilities on Schedule D-6.1 balances as of 12/31/19.
Purpose - To reflect the balances of Current Accrued and Other Liabilities and Other Capital items with-out double counting balances reflected on other lines of the capital structure.

(a) Supporting Schedules and Workpapers:
Schedule D-6.1
Schedule E-17B

(A) Recap Schedules:
Schedule D-1.2
Schedule D-1.3

Southwestern Electric Power Company
Analysis and Calculation of Customer Deposit Interest
Test Year Ending December 31, 2018
Docket No. 19-008-U

TOTAL AMOUNT OF DEPOSITS EARNING INTEREST:

	Unclassified Dep	AR Dep	LA Dep	TX Dep	Grand Total (a)
Sum of Dec 2017	-	15,434,982	32,564,524	14,113,061	62,112,567
Sum of Jan 2018	-	15,431,128	32,733,736	14,118,557	62,283,421
Sum of Feb 2018	-	15,447,523	32,856,616	14,186,417	62,490,556
Sum of Mar 2018	-	15,496,239	33,099,404	14,271,937	62,867,580
Sum of Apr 2018	-	15,538,937	33,278,757	14,345,918	63,163,611
Sum of May 2018	-	15,629,505	33,795,778	14,379,087	63,804,370
Sum of Jun 2018	-	15,657,120	33,972,590	14,379,121	64,008,831
Sum of Jul 2018	-	15,635,045	33,996,539	14,297,602	63,929,187
Sum of Aug 2018	-	15,635,045	33,996,539	14,297,602	63,929,187
Sum of Sep 2018	-	15,635,045	33,996,539	14,297,602	63,929,187
Sum of Oct 2018 (Proj)	-	15,635,045	33,996,539	14,297,602	63,929,187
Sum of Nov 2018 (Proj)	-	15,635,045	33,996,539	14,297,602	63,929,187
Sum of Dec 2018 (Proj)	-	15,635,045	33,996,539	14,297,602	63,929,187
13-Month Average		15,572,747	33,560,049	14,275,362	63,408,158

Note:
Unclassified Deposits are a result of timing differences between the General Ledger and the Customer billing system.

Test Year Interest Expense on Customer Deposits, account 4310002

	(b)	
Jan 2018	153,816	
Feb 2018	138,740	
Mar 2018	154,605	
Apr 2018	151,023	
May 2018	156,505	
Jun 2018	154,975	
Jul 2018	159,311	
Aug 2018	148,404	
Sep 2018	143,913	
Oct 2018 (Proj)	148,018	
Nov 2018 (Proj)	143,834	
Dec 2018 (Proj)	152,033	
Total Customer Deposit Interest Expense		1,805,178
13-Month Average of Customer Deposits		63,408,158

2018 Applicable interest rates on customer deposits

State	EffectiveDate	Rate
AR	1/1/2016	0.30%
LA	1/4/1992	5.00%
TX	1/1/2018	0.91%

As Adjusted	Deposits	Int. rate	Weighted Cost
Arkansas	15,572,747	0.30%	0.07%
Louisiana	33,560,049	5.00%	2.65%
Texas	14,275,362	0.91%	0.20%
	63,408,158		2.92%

Supporting Schedules and Workpapers:
(a) Schedule D-6.2
(b) Schedule E-17A

Recap Schedules:
(A) Schedule D-1.2

Southwestern Electric Power Company
Money Pool Interest Rate Calculation
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP D-1-3

	Date	Interest Rate %
Utility Money I	2018-12-01	2.00219210
Utility Money I	2018-12-02	2.00219210
Utility Money I	2018-12-03	2.00226810
Utility Money I	2018-12-04	2.00215681
Utility Money I	2018-12-05	2.68409659
Utility Money I	2018-12-06	2.69172596
Utility Money I	2018-12-07	2.68776912
Utility Money I	2018-12-08	2.68776912
Utility Money I	2018-12-09	2.68776912
Utility Money I	2018-12-10	2.78855503
Utility Money I	2018-12-11	2.79391784
Utility Money I	2018-12-12	2.79794603
Utility Money I	2018-12-13	2.81418937
Utility Money I	2018-12-14	2.77417004
Utility Money I	2018-12-15	2.77417004
Utility Money I	2018-12-16	2.77417004
Utility Money I	2018-12-17	2.88189355
Utility Money I	2018-12-18	2.90661460
Utility Money I	2018-12-19	2.90661462
Utility Money I	2018-12-20	2.94699175
Utility Money I	2018-12-21	2.95902165
Utility Money I	2018-12-22	2.95902165
Utility Money I	2018-12-23	2.95902165
Utility Money I	2018-12-24	2.95880041
Utility Money I	2018-12-25	2.95880041
Utility Money I	2018-12-26	2.96544699
Utility Money I	2018-12-27	2.97260622
Utility Money I	2018-12-28	2.97213734
Utility Money I	2018-12-29	2.97213734
Utility Money I	2018-12-30	2.97213734
Utility Money I	2018-12-31	2.97233455
December 2018 Average Interest Rate		2.74931089

Supporting Schedules and Workpapers:

Recap Schedules:
(A) Schedule D-1.2

Southwestern Electric Power Company
Common Equity Reconciliation
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP D 1-4

Line No.	Acct No.	Description	Per Books 7/31/2018(a)		Adjustments	Test Year 12/31/2018(a)		2019 Activity	Adjusted Pro forma 12/31/2019(a)
1	2010001	Common Stock Issued-Affiliated	135,659,520		2,087,822	137,747,342		5,705,862	143,453,204
2	2070003	Prem on Pfd Stk n/s/t Mand Red				0			0
3	2080000	Donations Recvd from Stckhldrs				0			0
4	2100000	Gain Rsle/Cancl Req Cap Stock	2,106,937		32,427	2,139,364		88,618	2,227,982
5	2110000	Miscellaneous Paid-In Capital	674,443,764		10,379,799	684,823,563		28,367,219	713,190,782
6	2190004	OCI-Min Pen Liab FAS 158-SERP				0		0	0
7	2190006	OCI-Min Pen Liab FAS 158-Qual				0		0	0
8	2190007	OCI-Min Pen Liab FAS 158-OPEB	1,569,791	(1)	(1,569,791)	(0)		0	(0)
9	2190015	Accum OCI-Hdg-CF-Int Rate	(6,117,986)	(2)	6,117,986	0		0	0
10	2190016	Accum OCI-Hdg-CF-For Exchg				0		0	0
11		Net Income (Loss) excluding PSD				0		0	0
12		Less: Dividends				0		0	0
13	2160001	Unapprp Retnd Erngs-Unrstrictd	1,476,407,143		22,722,145	1,499,129,288		62,097,936	1,561,227,224
14	2161001	Unap Undist Consol Sub Erng	11,406,571		175,549	11,582,120		479,762	12,061,882
15	2161002	Unap Undist Nonconsol Sub Erng	20,337,918		313,003	20,650,921		855,417	21,506,338
16	4370000	Div Decl-PS Not Sub to Man Red	0			0			0
17	4380001	Div Declrd - Common Stk - Asso	(40,000,000)		(615,606)	(40,615,606)		(1,682,407)	(42,298,013)
18	4390000	Adj to Retained Earnings	(399,935)		(6,155)	(406,090)		(16,821)	(422,911)
19			2,275,413,723		39,637,179	2,315,050,902		95,895,586	2,410,946,488
20		less: Turk Exclusion				374,353,880	(3)		376,719,972
21		**Total Common Equity**				**1,940,697,022**			**2,034,226,516**

Adjustments
(1) eliminate OCI since charge has not flown through results of operations
(2) Settled Interest Swaps reclassified to long term debt and included in Schd D-2.2 and Schd D-2.3
(3) Turk Exclusion

Supporting Schedules:
E-17B
WP B 2-7

Recap Schedules:
D-1.2
D-1.3

Southwestern Electric Power Company **WP D 1-5**
Adjusted Weighted Cost of Debt - Support
Test Year Ending December 31, 2018
Docket No. 19-008-U

		Adjusted Test Year
Total Cost of Capital		5.21%
Less Weighted Cost of Debt		-1.61%
Cost of Equity		3.60%
Revenue Conversion Factor	(a)	1.358174
		4.89%
Plus Weighted Cost of Debt		1.61%
Pretax Cost of Capital		**6.50%**

Weighted Cost of Debt	Proportion	Cost Rates	Adjusted Test Year Weighted Cost of Debt
LTD	33.63%	4.28%	1.44117%
ST Debt	0.56%	3.36%	0.01866%
Cust Deposits	1.08%	2.92%	0.03152%
Factored Receivables&IPP Upgrades	2.99%	3.88%	0.11623%
ITC - LTD	0.04%	4.28%	0.00188%
ITC - STD	0.00%	3.36%	0.00002%
Weighted Cost of Debt			1.60947%

Southwestern Electric Power Company
Adjusted Weighted Cost of Debt - Support
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP D 1-5

Description	Amount(b)	Proportion	Rate	Adjusted Test Year Weighted Cost
Long Term Debt	1,995,491,220	33.63%	4.28%	1.441174%
Preferred Stock	0	0.00%	0.00%	0.000000%
Common Equity	2,034,226,516	34.29%	10.50%	3.600091%
Accumulated Deferred Incc	651,070,108	10.97%	0.00%	0.000000%
ADITC - Debt	2,600,616	0.04%	4.28%	0.001878%
ADITC - Equity	1,647,798	0.03%	10.50%	0.002916%
ADITC - STD	26,688	0.00%	3.36%	0.000015%
Customer Deposits	63,929,187	1.08%	2.92%	0.031516%
Short Term/Interim Debt	32,946,320	0.56%	3.36%	0.018658%
Current, Accrued and Othe	973,504,066	16.41%	0.00%	0.000000%
Other Capital Items	177,568,060	2.99%	3.88%	0.116228%
Totals	5,933,010,580	100.00%		5.212477%

For Allocation of ITC		
Debt excluding ITC	3,210,492,534	60.832%
STD excluding ITC	32,946,320	0.624%
Equity excluding ITC	2,034,226,516	38.544%
	5,277,665,370	100.000%
ITC	4,275,102	
	5,281,940,472	
ADIT	651,070,108	

Supporting Schedules:
(a) C-5
(b) D-1.3

Recap Schedules:
WP C 11-2

Southwestern Electric Power Company
Other Capital Items
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP D-1-6

		Adjusted Test Year Balance	Interest Rate		Weighted Cost	Adjusted Pro Forma Year	Interest Rate	Weighted Cost
1420022	Cust A/R - Factored - 2018 13-mos. avg	115,255,205				115,255,205		
2340033	A/P Assoc Co - Factored A/R 13-mos avg	47,469,902				47,469,902		
		162,725,107	3.77%	(a)	3.61%	162,725,107	3.77%	3.45%
2530067	IPP - System Upgrade Credits(a)	7,060,546	5.18%	(b)	0.22%	14,842,953	5.18%	0.43%
		169,785,653			3.82%	177,568,060		3.88%

(a) Average Dec. 2018 carrying cost rate
(b) Calculated in accordance with FERC Commission regulations Section 35.19a. This rate is the annual rate applied to 1st quarter 2019

Supporting Schedules:
E-17B

Recap Schedules:
D-1.2
D-1.3

Southwestern Electric Power Company **SCHEDULE D-2.1**
Cost of Long Term Debt - Per Books Test Year
Test Year Ending December 31, 2018
Docket No. 19-008-U

This Schedule is not required for a partially projected test year.

Southwestern Electric Power Company
Cost of Long Term Debt - Projected Test Year
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE D-2.2

Explanation: Schedule showing computation of cost of total company long-term debt at the end of the projected test year. Schedule D-2.2 should only be completed if the company is filing a partially projected test year.

Projected Test Year as of 12/31/2018 - Long-Term Debt by Issue Including Current Maturities

(1) Line No.	(2) Description of Debt	(3) Issue Date	(4) Maturity Date	(5) Amount Outstanding per Books (a)	(6) Unamortized Net Disc/Prem/Hedge Expense Gain/Loss on Reacquired Debt Accts (a)	(7) Net Proceeds (Col. 5 +/- Col. 6)	(8) Adjustments for Projected Portion of Test Year	(9) Net Proceeds Projected Test Year (Col. 7 +/- Col. 8)	(11) Stated Rate %	(12) Annual Interest (Col. 5 x Col. 11)	(13) Amortization Net Disc/Prem & Expense	(14) Projected Annual Cost (Col. 12 +/- Col. 13)
1	Series G	6/9/2008	1/15/2019	400,000,000	(145,233)	399,854,767	(399,854,767)	0		0	0	0
2	Series H	3/8/2010	3/15/2040	350,000,000	(2,529,484)	347,470,516	48,738	347,519,254	6.20%	21,700,000	116,970	21,816,970
3	Series I	2/3/2012	2/15/2022	275,000,000	(1,198,329)	273,801,671	136,494	273,938,165	3.55%	9,762,500	327,587	10,090,087
4	Series J	3/26/2015	4/1/2045	400,000,000	(6,676,588)	393,323,412	104,448	393,427,860	3.90%	15,600,000	250,676	15,850,676
5	Series K	9/29/2016	10/1/2026	400,000,000	(2,881,054)	397,118,946	148,367	397,267,313	2.75%	11,000,000	356,081	11,356,081
6	Series L	1/22/2018	2/1/2048	450,000,000	(5,498,863)	444,501,137	27,407	444,528,544	3.85%	17,325,000	186,819	17,511,819
7	Series M Note 1	9/13/2018	9/15/2028	-	0	-	570,540,071	570,540,071	4.25%	24,437,500	460,467	24,897,967
8	Parish of DeSoto, Series 2010	3/12/2010	1/1/2019	53,500,000	(21,002)	53,478,998	14,023	53,493,021	1.60%	856,000	33,656	889,656
9	Term Loan_Local Bank	6/28/2017	6/29/2020	115,000,000	(253,062)	114,746,938	55,433	114,802,371	3.51%	4,040,525	133,039	4,173,564
10	Totals		(c)	2,443,500,000	(19,203,615)	2,424,296,385	171,220,214	2,595,516,599		104,721,525	1,865,296	106,586,821
11	Unamortized Loss/(Gain) on Reacquired Debt(a), (c)					(4,319,083)	(2,975,512)	(7,294,595)				652,483
12	Hedging Loss / (Gain) (AOCI) (d)					(7,744,286)	3,747,941	(3,996,345)				1,921,313
13	Total long term debt interest expense					**2,412,233,016**	171,992,643	**2,584,225,659 (A)**				**109,160,617 (B)**
14	Less: Turk Long Term-Debt Exclusion(b)							684,415,254				
15	Adjusted Total long term debt excluding Turk							**1,899,810,405**				
16	**Embedded Cost Rate - Line 17 (Col. 14 Total / Col. 9 Total) (B)**										**(B)**	**4.224% (B/A)**

Note 1 - $575M - 4.25 % Bond issue during projected year, Net proceeds at 12-31-2018 $570,540,071

Supporting Schedules and Workpapers:
(a) WP D-2.1
(b) WP B 2-5
(c) E-1
(d) E-17

Recap Schedules
Schedule D-1.2

Southwestern Electric Power Company
Cost of Long Term Debt - Pro Forma Year
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE D-2.3

Explanation: Schedule showing computation of cost of total company long-term debt at the end of the pro forma year.

Pro Forma Year as of12/31/19 - Long-Term Debt by Issue Including Current Maturities

(1) Line No.	(2) Description of Debt	(3) Issue Date	(4) Maturity Date	(5) Amount Outstanding Beginning of Pro Forma Year (a)	(6) Unamortized Net Disc/Prem/Exp, Gain/Loss on Issuance Expense (a)	(7) Net Proceeds Beginning of Pro Forma Year (Col. 5 +/- Col. 6)	(8) Pro Forma Adjustments	(9)(a) Net Proceeds End of Pro Forma Year (Col. 7 +/- Col. 8)	(11) Stated Rate %	(12) Annual Interest (Col. 5 x Col. 11)	(13) Projected Amortization Net Disc/Prem & Expense(a)	(14) Projected Annual Cost (Col. 12 +/- Col. 13)
1	Series H	3/8/2010	3/15/2040	350,000,000	(2,480,746)	347,519,254	116,970	347,636,224	6.20%	21,700,000	116,970	21,816,970
2	Series I	2/3/2012	2/15/2022	275,000,000	(1,061,835)	273,938,165	327,587	274,265,752	3.55%	9,762,500	327,587	10,090,087
3	Series J	3/26/2015	4/1/2045	400,000,000	(6,572,140)	393,427,860	250,676	393,678,537	3.90%	15,600,000	250,676	15,850,676
4	Series K	9/29/2016	10/1/2026	400,000,000	(2,732,687)	397,267,313	356,081	397,623,394	2.75%	11,000,000	356,081	11,356,081
5	Series L	1/22/2018	2/1/2048	450,000,000	(5,471,456)	444,528,544	186,819	444,715,363	3.85%	17,325,000	186,819	17,511,819
6	Series M	9/13/2018	9/15/2028	575,000,000	(4,459,929)	570,540,071	460,467	571,000,538	4.25%	24,437,500	460,467	24,897,967
	Parish of DeSoto, Series 2010	3/12/2010	1/1/2019	53,500,000	(6,979)	53,493,021	(53,493,021)	-				
7	Term Loan_Local Bank - Variable Rate	6/28/2017	6/29/2020	115,000,000	(197,630)	114,802,370	133,040	114,935,411	3.51%	4,036,500	133,039	4,169,539
8	Term Loan - Projected March 2019 Issue	3/31/2019	3/31/2029	-	0	-	149,098,125	149,098,125	4.50%	6,750,000	-	6,750,000
9												
10					-	-	-	-		-	-	-
11	Totals			2,618,500,000	(22,983,401)	2,595,516,599	97,436,744	2,692,953,343		110,611,500	1,831,640	112,443,140
12												
13	Unamortized Loss/(Gain) on Reacquired Debt					(7,294,595)	648,583	(6,646,012)				652,483
14	Hedging Gain / (Loss) (AOCI)					(3,996,345)	1,921,313	(2,075,032)				1,921,313
15						2,584,225,659	100,006,640	**2,684,232,299** (A)				**115,016,936** (B)
16	Turk Long-Term Debt Exclusion(b)							688,741,079				
17	Adjusted Total long term debt excluding Turk							**1,995,491,220**				
18	**Embedded Cost Rate - Line 15 (Col. 14 Total / Col. 9 Total) (B)**										**(B)**	**4.285% (B / A)**

Supporting Schedules and Workpapers:
(a) WP D-2.1
WP B 2-5

Recap Schedules
Schedule D-1.3

Southwestern Electric Power Company
Adjusted Weighted Cost of Debt - Support
Test Year Ending December 31, 2018
Docket No. 19-008-U

ISSUE COSTS

Account 181	Account	Debt Issuance Costs at 12/31/2018	Pro Forma Adjustments	Balance Reclassification	Adjusted Bal 12/31/2018	DI & Discount Annual Amortization	DI & Discount Historical 7/31/2018	Adjusted Bal 12/31/2019
Sr. Unsecured Notes:								
Series G							123,491	
Series H	1810006	2,376,822			2,376,822	(112,071)	2,423,518	2,264,751
Series I	1810006	661,564			661,564	(214,562)	750,965	447,003
Series J	1810006	3,477,912			3,477,912	(132,073)	3,532,943	3,345,840
Series K	1810006	2,413,753			2,413,753	(314,481)	2,544,787	2,099,272
Series L	1810006	4,544,906			4,544,906	(154,869)	4,559,000	4,390,037
Series M	1810006	4,459,929			4,459,929	(460,467)	0	3,999,462
		17,934,887	0	0	17,934,887			16,546,365
Pollution Control Bonds:								
DeSoto 2004	1810002	6,979			6,979	(33,656)	21,002	
Sabine Series 2006	1810002	0			0			
		17,941,865	0	0	17,941,865		13,955,706	16,546,365
	1810002	0		0	0			
Local Credit Line Facility	1810003	197,629			197,629	(133,039)	253,062	64,589
Term Loan - Projected March 2019	1810003	0			0			901,875
Insurance								
DeSoto 2004	1810102	0			0			
Sabine Series 2006	1810102	0			0			
Book Balance		18,139,494	0	0	18,139,494	(1,555,217)	14,208,768	17,512,829

DISCOUNT	Account	Debt Discount Costs at 12/31/2018	Pro Forma Adjustments	Balance Reclassification	Adjusted Bal 12/31/2018			
Account 226								
Sr. Unsecured Notes:								
							21,742	
Series H	2260006	103,924			103,924	(4,900)	105,966	99,025
Series I	2260006	400,271			400,271	(113,025)	447,365	287,246
Series J	2260006	3,094,227			3,094,227	(118,604)	3,143,646	2,975,624
Series K	2260006	318,934			318,934	(41,600)	336,267	277,334
Series L	2260006	926,550			926,550	(31,950)	939,863	894,600
Series M		0					0	
		4,843,906	0	0	4,843,906			4,533,828
Pollution Control Bonds:								
Titus 2004		-			-			
DeSoto 2015		-	-		-			
Sabine Series 2006		-			-			
		4,843,906	0	0	4,843,906	(310,079)	4,973,106	4,533,828
Debt Issue + Discount Schedule D-2.3 - Col (6)		22,983,400	0	0	22,983,400	(1,865,296)		**22,046,657**

LOSS ON REACQUIRED DEBT

Account 189 & 257

	Account	12/31/2018 Unamortized Balance	Pro Forma Adjustments	Balance Reclassification	Adjusted Bal 12/31/2018	Annual Amortization		Adjust Bal 12/31/2019
BB Series	1890001	952,170			952,170	(152,347)		799,822
Z Series	1890001	1,182,926			1,182,926	(47,795)		1,135,131
S Series	1890001				0	0		0
L Series	1890001	9,195			9,195	(6,359)		2,836
1992 Desoto	1890002	137,982			137,982	(49,063)		88,920
1996 Sabine	1890002	0			0	0		0
Sabine 4-08 Refinance	1890002				0	0		0
DeSoto -Jan 2, 2015	1890002							0
Capital I Trust	1890004	1,840,570			1,840,570	(73,971)		1,766,598
Capital I Trust-10-2008	1890004	4,999			4,999	0		0
Ser G - Ret Oct 18	1890006	3,175,652			3,175,652	(322,948)		2,852,704
		7,303,494	0	0	7,303,494	(652,483)		6,646,012
Gain on Reacquired Debt								
Gain L Series	2570001	(8,899)			(8,899)	0		
TOTAL		7,294,595			7,294,595	(652,483)		6,646,012

Insurance Annual Cost	
DeSoto 2004	0
Sabine Series 2006	0

memo: Hedging transactions
Unamortized Loss (Gain)

	Series M Hedge Gain		
	09/12/18 Hedging Gain Initial Balance	12/31/18 Hedging Gain Balance	12/31/19 Hedging Gain Balance
AOCI deferred	(2,301,590)	(2,232,542)	(2,002,383)
ADIT	(611,815)	(593,461)	(532,279)
Total gain	**(2,913,405)**	**(2,826,003)**	**(2,534,662)**
Annual Amortization		**(291,340)**	**(291,340)**

	Series I Hedge Loss		
	02/01/12 Hedging Loss Initial Balance	12/31/18 Hedging Loss Balance	12/31/19 Hedging Loss Balance
AOCI deferred	14,382,246	5,389,654	3,641,658
ADIT	7,744,286	1,432,693	968,036
Total Loss	**22,126,532**	**6,822,347**	**4,609,694**
Annual Amortization		**2,212,653**	**2,212,653**

Combined	Total Loss (Gain)	3,996,345	2,075,032
	Amortization	1,921,313	1,921,313

Supporting Schedules:

Recap schedules:
Schedule D-2.2
Schedule D-2.3

Southwestern Electric Power Company **SCHEDULE D-3.2**
Cost of Preferred Stock- Projected Test Year
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing computation of total company cost of preferred stock at the end of the projected test year. Schedule D-3.2 should only be completed if the company is filing a partially projected test year.

(1) Line No.	(2) Description	(3) Issue Date	(4) Amount	(5) Rate %	(6) Dividend Requirement (Col. 4 x Col. 5)	(7) Shares Outstanding
1	No Preferred stock					

Supporting Schedules and Workpapers: Recap Schedules

Southwestern Electric Power Company
Cost of Common Equity
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE D-4

Explanation: Summary of conclusions on the required rate of return on common equity.

Description

Cost of Common Equity

Robert B. Hevert's analyses presented in Direct Testimony and Exhibits RBH-1 through RBH-9 indicate that SWEPCO's Cost of Equity currently is in the range of 10.25 percent to 11.00 percent. Based on Mr. Hevert's quantitative and qualitative analyses – including the Company's relative risk profile, past Commission precedent, and the guidance provided by Act 725 – he believes 10.50 percent is a reasonable and appropriate estimate of the Company's Cost of Equity.

Mr. Hevert relied on three widely-accepted approaches: (1) the Discounted Cash Flow ("DCF") model, including the Constant Growth and Quarterly Growth; (2) the Capital Asset Pricing Model ("CAPM"); and (3) the Bond Yield Plus Risk Premium approach.

In addition to the methodologies noted above, his recommendation also takes into consideration: (1) the risk associated with its dependence on coal-fired generation; (2) the Company's relative small size; and (3) the cost of issuing common stock. While he did not make any explicit adjustments to his ROE estimates for those factors, He did take them into consideration in determining where the Company's Cost of Equity falls within the range of analytical results. His ROE recommendation also considers the current financial environment and the effect of the Tax Cuts and Jobs Act ("TCJA"). As discussed throughout his testimony, although those factors are very relevant to investors, they do not lend themselves to direct quantification. Consequently, the application of judgment in assessing their effects on the Cost of Equity is unavoidable. Lastly, consistent with Act 725, Mr. Hevert considered authorized returns in jurisdictions in the same part of the United States as SWEPCO, and across the Country in general.

All of the models used by Mr. Hevert to estimate the Cost of Equity are subject to certain assumptions, which may become more or less relevant as market conditions, and market data, change. It therefore is important to consider a variety of empirical and qualitative information in reviewing analytical results and arriving at ROE recommendations. That review includes an assessment of the various models used, and the consistency of their underlying assumptions with current and expected market conditions. In the end, it is the reasonableness and consistency of the ROE determination that is of principal concern to investors.

His recommended range recognizes that certain models, in particular Discounted Cash Flow-based approaches, are based on assumptions that are inconsistent with current and expected market conditions. For example, the Constant Growth DCF model assumes that the return estimated today will be the same return required in the future, even though the Federal Reserve only recently has begun its move toward monetary policy normalization. That process of normalization, together with the uncertainty surrounding the "unwinding" of the assets put on the Federal Reserve's balance sheet during its "Quantitative Easing" initiatives introduce a degree of risk not present in the current market. Other methods more directly reflect the risk premium required by investors in response to market and industry risks. On balance, consistent with Act 725, Mr. Hevert's recommendation considers the range of results of multiple methods in the context of the Company's risk profile.

Supporting Schedules and Workpapers:

Recap Schedules
D-1.1, D-1.2, D-1.3

Southwestern Electric Power Company
Cost of Other Capital Items- Per Books Test Year
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE D-5.1

This schedule is not required for a partially projected test year.

Recap Schedules

Supporting Schedules and Workpapers:

Southwestern Electric Power Company **SCHEDULE D-5.2**
Cost of Other Capital Items- Projected Test Year
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing other elements of actual total company capital structure and the related costs at the end of the projected test year. Schedule D-5.2 should only be completed if the company is filing a partially projected test year. Schedule D-5.2 should include other elements of total company capital structure and the related costs not shown on Schedule D-2.2, D-3.2, and D-4 and should provide the same level of detail as shown on those schedules. ADITC should be shown in accordance with external capital proportions (e.g. long-term debt, short-term debt, preferred stock, common equity) in Schedule D-1.2.

		Projected Test Year as of December 31, 2018			
(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description of Item	Amount Per Books (a)	Adjustments for Projected Portion of Test Year	Projected Test Year (A) (Col. 3 +/- Col. 4)	Rate % (a)
1	Accumulated Deferred Income Taxes(b)	$ 911,071,417	$ (237,015,033)	$ 674,056,384	0.00%
2	ADITC - Debt (c)	3,088,198	(252,310)	2,835,887	4.22%
3	ADITC - Equity (c)	1,956,738	(159,868)	1,796,870	10.50%
4	ADITC - Short Term Debt (c)	31,691	(2,589)	29,102	2.75%
5	Short Term/Interim Debt (e)	106,690,962	(98,075,822)	8,615,140	2.75%
6	Customer Deposits (e)	63,929,187	-	63,929,187	2.92%
7	Current, Accrued and Other Liabilities (d)	1,362,890,803	(52,683,019)	1,310,207,784	0.00%
8	Other Capital Items (d)	207,042,962	(37,257,309)	169,785,653	3.82%
9	Totals	$ 2,656,701,958	$ (425,445,951)	$ 2,231,256,007	

Supporting Schedules and Workpapers:
(a) E-1
(b) C-10
(c) E1, WP D 1-5 or C9, WP D 1-5
(d) WP D-1-1
(e) E17-B

Recap Schedules
(A) Schedule D-1.2

Southwestern Electric Power Company
Cost of Other Capital Items- Pro Forma Year
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE D-5.3

Explanation: Schedule showing other elements of actual total company capital structure and the related costs at the end of the proforma year. Schedule D-5.3 should include other elements of total company capital structure and the related costs not shown on Schedules D-2.3, D-3.3, and D-4 and should provide the same level of detail as shown in those schedules. ADITC should be shown in accordance with external capital proportions (e.g. long-term debt, short-term debt, preferred stock, common equity) in Schedule D-1.3.

		Pro Forma Year Ending December 31, 2019			
(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description of Item	Beginning Pro Forma Year (a)	Pro Forma Adjustments	End of Pro Forma Year (a) (Col. 3 +/- Col. 4)	Rate % (a)
1	Accumulated Deferred Income Taxes(b)	$ 674,056,384	$ (22,986,276)	$ 651,070,108	0.00%
2	ADITC - Debt (c)	2,835,887	(235,271)	2,600,616	4.28%
3	ADITC - Equity (c)	1,796,870		1,647,798	10.50%
4	ADITC - Short Term Debt (c)	29,102		26,688	3.36%
5	Short Term/Interim Debt (d)	8,615,140	24,331,180	32,946,320	3.36%
6	Customer Deposits (d)	63,929,187	(0)	63,929,187	2.92%
7	Current, Accrued and Other Liabilities (ϵ	1,310,207,784	(336,703,718)	973,504,066	0.00%
8	Other Capital Items (e)	169,785,653	7,782,407	177,568,060	3.88%
9	Totals	$ 2,231,256,007	$ (327,811,678)	$ 1,903,292,844	
10	Cost Rate				

Supporting Schedules and Workpapers:
(a) D-5.2
(b) C-10
(c) C-9, WP D 1-5
(d) E-17B
(e) WP D 1-1

Recap Schedules
(A) Schedule D-1.3

Southwestern Electric Power Company **Schedule D-6.1**
Calculation of Current, Accrued and Other Liabilities
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing calculation of current, accrued, and other liabilities starting with the subaccount balances of all liabilities not included in Schedules D-2, D-3, and D-4 at the end of the test year, adjusting to 13-months averages; and making additional adjustments needed to result in the source of funds to the company not provided for elsewhere in the cost of service.

I. Liability subaccounts

Line No.	(1) Account No.	(2) Account Title	(3) Balance at end of Historical period	(4) Balance at End of Test year (A)(a)	(5) Adj. Needed to Achieve 13-Mnth Average (Col. 6 - Col. 4)	(6) 13 Month Average (a)	(7) Adjustment	(8) Adjustment Reference No.*	(9) Pro Forma CAOL(B)
1	2270001	Obligatns Undr Cap Lse-Noncur	22,886,956	18,931,701	3,563,782	22,495,483			22,495,483
2	2270003	Accrued Noncur Lease Oblig	99,637	82,418	127,351	209,769			209,769
3	2282003	Accm Prv I/D - Worker's Com	87,519	87,519	(6,034)	81,485			81,485
4	2283000	Accm Prv for Pensions&Benefits	1,120,278	1,483,024	(294,021)	1,189,003			1,189,003
5	2283001	Deferred Compensation Plan	1,695,071	2,243,936	(422,204)	1,821,732			1,821,732
6	2283002	Supplemental Savings Plan	1,059,458	1,402,510	(218,866)	1,183,644			1,183,644
7	2283005	SFAS 112 Postemployment Ben	4,042,857	5,351,935	(1,112,045)	4,239,890			4,239,890
8	2283006	SFAS 87 - Pensions	4,734,192	6,267,124	(2,627,759)	3,639,365			3,639,365
9	2283007	Perf Share Incentive Plan	0	0	451,120	451,120			451,120
10	2283013	Incentive Comp Deferral Plan	135,850	179,838	(37,773)	142,065			142,065
11	2283015	FAS 158 SERP Payable Long T	950,674	1,258,502	(226,827)	1,031,675	(1,031,675)	(6)	0
12	2283016	FAS 158 Qual Payable Long Te	(1,844,975)	(2,442,378)	1,326,784	(1,115,594)	1,115,594	(6)	0
13	2290002	Acc Prv Rate Refnds-Nonassoc	6,211,117	6,649,561	938,344	7,587,905	(7,587,905)	(6)	0
14	2290006	Acc Prv for Potential Refund	(0)	0	755,860	755,860	(755,860)	(6)	0
15	2290018	Acc Prov Refunds - Tax Reform	29,008,073	31,055,758	(10,768,056)	20,287,702	(20,287,702)	(1)	0
16	2290019	Acc Prov Refund-Excess Protec	8,184,185	8,761,908	(3,058,057)	5,703,851	(5,703,851)	(1)	0
17	2300001	Asset Retirement Obligations	101,333,095	101,802,860	(8,623,504)	93,179,356	(93,179,356)	(6)	0
18	2300002	ARO - Current	12,595,939	12,654,331	(1,741,613)	10,912,718	(10,912,718)	(6)	0
19	2320001	Accounts Payable - Regular	19,812,013	19,812,013	9,059,753	28,871,766			28,871,766
20	2320002	Unvouchered Invoices	21,336,094	21,336,094	3,317,111	24,653,205			24,653,205
21	2320003	Retention	7,191,769	7,191,769	(701,824)	6,489,945			6,489,945
22	2320008	Miscellaneous Liabilities	0	0	0	0			0
23	2320011	Uninvoiced Fuel	26,631,678	26,631,678	(3,356,270)	23,275,408	(1,634,640)	WP D 6-1	21,640,768
24	2320052	Accounts Payable - Purch Powe	8,541,661	8,541,661	1,282,391	9,824,052			9,824,052
25	2320054	Emission Allowance Trading	(1,325)	(1,325)	4,050	2,725			2,725
26	2320062	Broker Fees Payable	4,140	4,140	(529)	3,611			3,611
27	2320066	A/P - OPEN ACCESS TRANS E	11,671,842	11,671,842	(85,050)	11,586,792			11,586,792
28	2320075	Unvouch - Dolet Hills - Cleco	1,486,927	1,486,927	134,101	1,621,028			1,621,028
29	2320076	Corporate Credit Card Liab	196,636	196,636	35,196	231,832			231,832
30	2320077	INDUS Unvouchered Liabilities	1,554,784	1,554,784	1,706,291	3,261,075			3,261,075
31	2320089	Mattison-Centerpoint Payable	8,773,177	8,773,177	(1,233,352)	7,539,825			7,539,825
32	2320090	MISO AP Accrual	642,667	642,667	(54,592)	588,075			588,075
33	2330000	Corp Borrow Program (NP-Asso	106,690,962	8,615,140	66,169,064	74,784,204	(74,784,204)	(2)	0
34	2340001	A/P Assoc Co - InterUnit G/L	34,865,728	34,865,728	(3,920,771)	30,944,957			30,944,957

Southwestern Electric Power Company **Schedule D-6.1**
Calculation of Current, Accrued and Other Liabilities
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing calculation of current, accrued, and other liabilities starting with the subaccount balances of all liabilities not included in Schedules D-2, D-3, and D-4 at the end of the test year, adjusting to 13-months averages; and making additional adjustments needed to result in the source of funds to the company not provided for elsewhere in the cost of service.

I. Liability subaccounts

Line No.	(1) Account No.	(2) Account Title	(3) Balance at end of Historical period	(4) Balance at End of Test year (A)(a)	(5) Adj. Needed to Achieve 13-Mnth Average (Col. 6 - Col. 4)	(6) 13 Month Average (a)	(7) Adjustment	(8) Adjustment Reference No.*	(9) Pro Forma CAOL(B)
35	2340025	A/P Assoc Co - CM Bills	31,051	31,051	23,422	54,473			54,473
36	2340027	A/P Assoc Co - Intercompany	218,189	218,189	146,076	364,265			364,265
37	2340029	A/P Assoc Co - AEPSC Bills	15,113,837	15,113,837	(918,162)	14,195,675			14,195,675
38	2340030	A/P Assoc Co - InterUnit A/P	63,566	63,566	292,680	356,246			356,246
39	2340032	A/P Assoc Co - Multi Pmts	13,582	13,582	(4,751)	8,831			8,831
40	2340033	A/P Assoc Co - Factored A/R	55,428,382	55,428,382	(4,658,620)	50,769,762			50,769,762
41	2340035	Fleet - M4 - A/P	8,250	8,250	2,907	11,157			11,157
42	2340041	A/P Assc Co - Non-InterUnit GL	14,903,072	14,903,072	(1,162,203)	13,740,869			13,740,869
43	2350001	Customer Deposits-Active	63,929,187	63,929,187	(521,029)	63,408,158	(63,408,158)	(2)	0
44	2350003	Deposits - Trading Activity	(0)	0	47,027	47,027	(47,027)	(5)	0
45	2360001	Federal Income Tax	(5,434,102)	(2,363,156)	(2,077,807)	(4,440,963)			(4,440,963)
46	23600021	State Income Taxes	(12,320)	(5,358)	(6,240)	(11,598)			(11,598)
47	23600021	State Income Taxes	0	0	0	0			0
48	23600021	State Income Taxes	(845,451)	(367,666)	(101,318)	(468,984)			(468,984)
49	23600021	State Income Taxes	2,332,721	1,014,443	272,094	1,286,537			1,286,537
50	2360004	FICA	462,940	201,321	180,027	381,348	(24,368)	WP D 6-1	356,980
51	2360005	Federal Unemployment Tax	708	308	16,931	17,239	(1,102)	WP D 6-1	16,138
52	2360006	State Unemployment Tax	780	339	18,341	18,680	(1,194)	WP D 6-1	17,486
53	23600070	State Sales and Use Taxes	0	0	72,962	72,962			72,962
54	23600071	State Sales and Use Taxes	0	0	0	0			0
55	23600071	State Sales and Use Taxes	(263,277)	(114,492)	186,716	72,224			72,224
56	23600071	State Sales and Use Taxes	1,147,409	498,980	632,205	1,131,185	(156,640)	WP D 6-1	974,545
57	23600081	Real Personal Property Taxes	0	0	0	0			0
58	23600081	Real Personal Property Taxes	7,475,761	3,251,023	8,045,019	11,296,042			11,296,042
59	23600081	Real Personal Property Taxes	64,324,692	27,973,216	28,325,670	56,298,886	(5,344,818)	WP D 6-1	50,954,068
60	23600120	State Franchise Taxes	0	0	0	0			0
61	23600121	State Franchise Taxes	0	0	0	0			0
62	23600121	State Franchise Taxes	(363,856)	(158,232)	(184,302)	(342,534)			(342,534)
63	23600121	State Franchise Taxes	(1,505,000)	(654,487)	50,780	(603,707)			(603,707)
64	23600201	State Public Service Com Tax	0	0	0	0			0
65	23600201	State Public Service Com Tax	1,436,652	624,764	555,074	1,179,838			1,179,838
66	23600201	State Public Service Com Tax	291,721	126,862	47,914	174,776			174,776
67	23600220	State License/Registration Tax	0	0	0	0			0
68	23600220	State License/Registration Tax	0	0	0	0			0

Southwestern Electric Power Company **Schedule D-6.1**
Calculation of Current, Accrued and Other Liabilities
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing calculation of current, accrued, and other liabilities starting with the subaccount balances of all liabilities not included in Schedules D-2, D-3, and D-4 at the end of the test year, adjusting to 13-months averages; and making additional adjustments needed to result in the source of funds to the company not provided for elsewhere in the cost of service.

I. Liability subaccounts

Line No.	(1) Account No.	(2) Account Title	(3) Balance at end of Historical period	(4) Balance at End of Test year (A)(a)	(5) Adj. Needed to Achieve 13-Mnth Average (Col. 6 - Col. 4)	(6) 13 Month Average (a)	(7) Adjustment	(8) Adjustment Reference No.*	(9) Pro Forma CAOL(B)
69	23600251	Local Franchise Tax	0	0	0	0			0
70	23600251	Local Franchise Tax	0	0	286,105	286,105			286,105
71	23600251	Local Franchise Tax	1,975,255	858,989	1,150,167	2,009,156			2,009,156
72	23600331	Pers Prop Tax-Cap Leases	0	0	0	0			0
73	23600331	Pers Prop Tax-Cap Leases	8,493	3,693	6,527	10,220			10,220
74	23600331	Pers Prop Tax-Cap Leases	173,000	75,233	74,321	149,554			149,554
75	2360037	FICA - Incentive accrual	524,210	227,966	235,299	463,265	(40,312)	WP D 6-1	422,953
76	2360501	Fed Inc Tax-Short Term FIN48	(0)	0	(76,042)	(76,042)	76,042	(6)	0
77	2360502	State Inc Tax-Short Term FIN48	53,646	23,329	27,173	50,502	(50,502)	(6)	0
78	2360601	Fed Inc Tax-Long Term FIN48	0	0	(66,572)	(66,572)	66,572	(6)	0
79	2360602	State Inc Tax-Long Term FIN48	(761,734)	(331,259)	(385,837)	(717,096)	717,096	(6)	0
80	2360701	SEC Accum Defd FIT-Util FIN 48	0	0	(0)	(0)	0	(6)	0
81	2360702	SEC Accum Defd SIT - FIN 48	(99,070)	(99,768)	581	(99,187)	99,187	(6)	0
82	2360801	Federal Income Tax - IRS Audit	0	0	28,552	28,552			28,552
83	2360901	Accum Defd FIT- IRS Audit	0	0	625,958	625,958			625,958
84	2370002	Interest Accrued-Inst Pur Con	71,333	88,581	470,072	558,653	(558,653)	(2)	0
85	2370005	Interest Accrd-Other LT Debt	87,640	108,830	80,370	189,200	(189,200)	(2)	0
86	2370006	Interest Accrd-Sen Unsec Notes	31,789,517	39,475,688	(8,264,046)	31,211,642	(31,211,642)	(2)	0
87	2370007	Interest Accrd-Customer Depsts	979,957	1,216,894	(411,476)	805,418	(805,418)	(2)	0
88	2370018	Accrued Margin Interest	0	0	(0)	(0)			(0)
89	2370025	Interest Over Recover - AR	0	0	0	0			0
90	2370348	Acrd Int. - SIT Reserve - LT	88,336	109,694	(59,289)	50,405			50,405
91	2370448	Acrd Int. - SIT Reserve - ST	20,788	25,814	(6,628)	19,186			19,186
92	2380003	Div Decl - Common Stock-Affil	0	0	0	0			0
93	2410002	State Income Tax Withheld	182,911	182,911	23,919	206,830	(13,217)	WP D 6-1	193,614
94	2410003	Local Income Tax Withheld	0	0	64	64	(4)	WP D 6-1	60
95	2410004	State Sales Tax Collected	4,957,391	4,957,391	(1,012,319)	3,945,072			3,945,072
96	2410005	FICA Tax Withheld	0	0	848	848	(54)	WP D 6-1	794
97	2410008	Franchise Fee Collected	1,899,362	1,899,362	356,714	2,256,076			2,256,076
98	2420000	Misc Current & Accrued Liab	18,069	18,471	(309)	18,162			18,162
99	2420002	P/R Ded - Medical Insurance	357,067	365,007	(6,004)	359,003	(22,940)	WP D 6-1	336,062
100	2420003	P/R Ded - Dental Insurance	43,274	44,236	(751)	43,485	(2,779)	WP D 6-1	40,707
101	2420007	P/R Ded - Savings Plan	0	0	5	5			5
102	2420010	P/R Ded - Dependent Life Ins	3	3	(2)	1			1

Southwestern Electric Power Company
Calculation of Current, Accrued and Other Liabilities
Test Year Ending December 31, 2018
Docket No. 19-008-U

Schedule D-6.1

Explanation: Schedule showing calculation of current, accrued, and other liabilities starting with the subaccount balances of all liabilities not included in Schedules D-2, D-3, and D-4 at the end of the test year, adjusting to 13-months averages; and making additional adjustments needed to result in the source of funds to the company not provided for elsewhere in the cost of service.

I. Liability subaccounts

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.	Account No.	Account Title	Balance at end of Historical period	Balance at End of Test year (A)(a)	Adj. Needed to Achieve 13-Mnth Average (Col. 6 - Col. 4)	13 Month Average (a)	Adjustment	Adjustment Reference No.*	Pro Forma CAOL(B)
103	2420013	P/R Ded - LTD Ins Premiums	5,149	5,264	(75)	5,189	(332)	WP D 6-1	4,857
104	2420016	P/R Ded-Crt Ordr/Grnshmt/Tx Lv	10	10	(5)	5			5
105	2420017	P/R Ded - AD&D and OAD&D In	12	12	(6)	6			6
106	2420018	P/R Ded-Reg&Spec Life Ins Pre	23	24	(13)	11			11
107	2420020	Vacation Pay - This Year	7,279,059	7,440,937	669,790	8,110,727	(500,056)	WP D 6-1	7,610,672
108	2420021	Vacation Pay - Next Year	5,719,633	5,846,831	(726,381)	5,120,450	(388,584)	WP D 6-1	4,731,866
109	2420027	FAS 112 CURRENT LIAB	1,510,149	1,543,733	(84,143)	1,459,590	(93,269)	WP D 6-1	1,366,321
110	2420028	ESP - Employer Contrib Accrued	0	0	4	4			4
111	2420046	FAS 158 SERP Payable - Curren	150,521	153,868	(2,575)	151,293	(151,293)	(6)	0
112	2420051	Non-Productive Payroll	462,130	472,407	(96,305)	376,102	(24,033)	WP D 6-1	352,068
113	2420053	Perf Share Incentive Plan	1,184,551	1,210,894	(120,896)	1,089,998			1,089,998
114	2420059	MINE CLOSING COSTS - FERC	0	0	0	0			0
115	2420071	P/R Ded - Vision Plan	17,193	17,575	(316)	17,259	(1,103)	WP D 6-1	16,156
116	2420072	P/R - Payroll Adjustment	2,420	2,474	(1,047)	1,427	(91)	WP D 6-1	1,336
117	2420076	P/R Savings Plan - Incentive	279,872	286,096	(20,217)	265,879	(16,990)	WP D 6-1	248,889
118	2420081	Environmntl Remediation Accrua	26,137	26,718	(447)	26,271			26,271
119	2420083	Active Med and Dental IBNR	0	0	21,130	21,130			21,130
120	2420504	Accrued Lease Expense	360,828	368,852	21,530	390,382			390,382
121	2420511	Control Cash Disburse Account	5,772,907	5,901,290	(109,647)	5,791,643			5,791,643
122	2420512	Unclaimed Funds	39,554	40,434	(7,419)	33,015			33,015
123	2420514	Revenue Refunds Accrued	7,489,219	7,655,771	(2,813,708)	4,842,063	(4,842,063)	(3)	0
124	2420519	Provision for Unclaimed Funds	0	0	0	0			0
125	2420532	Adm Liab-Cur-S/Ins-W/C	150,645	153,995	(14,690)	139,305			139,305
126	24205381	Federal Admin Fee	0	0	2,823	2,823			2,823
127	2420558	Admitted Liab NC-Self/Ins-W/C	534,692	546,583	(111,567)	435,016			435,016
128	24205921	Sales Use Tax - Leased Equip	0	0	0	0			0
129	24205921	Sales Use Tax - Leased Equip	0	0	15	15			15
130	24205921	Sales Use Tax - Leased Equip	3,860	3,946	(264)	3,682			3,682
131	2420618	Accrued Payroll	5,492,497	5,614,644	(713,718)	4,900,926	(275,418)	WP D 6-1	4,625,508
132	2420623	Distr, Cust Ops & Reg Svcs ICP	3,376,429	3,451,517	(256,214)	3,195,303			3,195,303
133	2420624	Corp & Shrd Srv Incentive Plan	404,115	413,102	(20,546)	392,556			392,556
134	2420635	Generation Incentive Plan	2,856,281	2,919,801	(225,562)	2,694,239	(172,163)	WP D 6-1	2,522,075
135	2420643	Accrued Audit Fees	141,373	144,517	12,114	156,631			156,631
136	2420644	Reclamation Liability - Affil	78,480,216	80,225,528	(1,975,516)	78,250,012			78,250,012

Southwestern Electric Power Company
Calculation of Current, Accrued and Other Liabilities
Test Year Ending December 31, 2018
Docket No. 19-008-U

Schedule D-6.1

Explanation: Schedule showing calculation of current, accrued, and other liabilities starting with the subaccount balances of all liabilities not included in Schedules D-2, D-3, and D-4 at the end of the test year, adjusting to 13-months averages; and making additional adjustments needed to result in the source of funds to the company not provided for elsewhere in the cost of service.

I. Liability subaccounts

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.	Account No.	Account Title	Balance at end of Historical period	Balance at End of Test year (A)(a)	Adj. Needed to Achieve 13-Mnth Average (Col. 6 - Col. 4)	13 Month Average (a)	Adjustment	Adjustment Reference No.*	Pro Forma CAOL(B)
137	2420649	Reclamation Liability - Curr	813	831	580	1,411			1,411
138	2420660	AEP Transmission ICP	532,033	543,865	(8,135)	535,730			535,730
139	2420662	Accrued Railcar Lease Exp - ST	12,687	12,969	(217)	12,752			12,752
140	2420663	Accrued railcar lease exp - LT	93,146	95,218	1,575	96,793			96,793
141	2420665	Dollar Energy Assistance Pgm	1,115	1,140	194	1,334			1,334
142	2420700	Quality of Service	212,399	217,123	(101,664)	115,459			115,459
143	2430001	Oblig Under Cap Leases - Curr	4,144,100	6,203,813	(2,163,676)	4,040,137			4,040,137
144	2430003	Accrued Cur Lease Oblig	24,909	37,290	(1,806)	35,484			35,484
145	2440001	Curr. Unreal Losses - NonAffil	212,268	212,268	13,522	225,790			225,790
146	2440002	LT Unreal Losses - Non Affil	2,580,153	2,580,153	(797,493)	1,782,660			1,782,660
147	2530000	Other Deferred Credits	6,075,648	6,177,808	(1,339,088)	4,838,720			4,838,720
148	2530022	Customer Advance Receipts	3,415,040	3,472,462	596,393	4,068,855			4,068,855
149	2530050	Deferred Rev -Pole Attachments	2,182,849	2,219,553	(902,936)	1,316,617			1,316,617
150	2530067	IPP - System Upgrade Credits	6,943,788	7,060,546	(135,992)	6,924,554	(6,924,554)	(2)	0
151	2530101	MACSS Unidentified EDI Cash	2,435	2,476	1,936	4,412			4,412
152	2530104	Railroad Cars Subleased-Rev	(141)	(144)	3,504	3,360			3,360
153	2530112	Other Deferred Credits-Curr	160,777	163,481	47,292	210,773	(74,102)	WP D 6-1	136,672
154	2530120	Environ Remediation LT	143,957	136,452	5,773	142,225			142,225
155	2530124	Contr In Aid of Constr Advance	318,300	301,706	71,762	373,468			373,468
156	2530139	IPP - Aff. Sys Upgrade Credits	0	0	0	0			0
157	2530181	Oxbow Buy In	2,807,662	2,854,872	(19,118)	2,835,754			2,835,754
158	2530185	O\U Accounting of ExpensesT	(12,043)	(12,245)	22,376	10,131			10,131
159	2530188	Long Term Assoc AP	3,654,588	3,716,039	(1,734,065)	1,981,974			1,981,974
160	2530190	QUAL OF SVC PENALTIES - LT	0	0	23,305	23,305			23,305
161	2540047	Unreal Gain on Fwd Commitmer	195,847	185,637	337,543	523,180			523,180
162	2540050	Def Rev Selling Price Variance	(0)	0	138,291	138,291			138,291
163	2540052	EXCESS EARNINGS	2,573,476	2,439,310	116,128	2,555,438	(2,555,438)	(5)	0
164	2540058	Dolet Hills Mining Buy-Out	272,906	258,678	10,944	269,622	(269,622)	(5)	0
165	2540090	Over Recovered Fuel Cost - TX	12,424,402	0	4,215,537	4,215,537	(4,215,537)	(5)	0
166	2540094	Over Recovered Fuel Cost - LA	5,230,602	0	759,116	759,116	(759,116)	(5)	0
167	2540118	Energy Efficiency O/U Recovery	594,898	563,884	(197,601)	366,283	(366,283)	(5)	0
168	2540137	Over Recovered EAC - LA	0	0	2,606	2,606	(2,606)	(5)	0
169	2540139	Refundable Construction Int-LA	0	0	0	0			0
170	2540174	JLStall GR Rider Over Recovery	2,462,265	2,333,896	(364,046)	1,969,850	(1,969,850)	(5)	0

Southwestern Electric Power Company **Schedule D-6.1**
Calculation of Current, Accrued and Other Liabilities
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing calculation of current, accrued, and other liabilities starting with the subaccount balances of all liabilities not included in Schedules D-2, D-3, and D-4 at the end of the test year, adjusting to 13-months averages; and making additional adjustments needed to result in the source of funds to the company not provided for elsewhere in the cost of service.

I. Liability subaccounts

Line No.	(1) Account No.	(2) Account Title	(3) Balance at end of Historical period	(4) Balance at End of Test year (A)(a)	(5) Adj. Needed to Achieve 13-Mnth Average (Col. 6 - Col. 4)	(6) 13 Month Average (a)	(7) Adjustment	(8) Adjustment Reference No.*	(9) Pro Forma CAOL(B)
171	2540184	Texas Vegetation Management	2,859,454	2,710,379	642,364	3,352,743	(3,352,743)	(5)	0
172	2540191	LA SQIP Veg Mgmt O/U Recove	3,142,610	2,978,773	(618,922)	2,359,851	(2,359,851)	(5)	0
173	2543001	SFAS109 Flow Thru Def FIT Lial	1,349,483	1,328,881	83,834	1,412,715			1,412,715
174	2544001	SFAS 109 Exces Deferred FIT	706,704,599	695,915,578	11,013,421	706,928,999	(202,436,056)	(7)	504,492,943
175	2544009	OCI - Excess DFIT	0	0	(194,600)	(194,600)			(194,600)
176	2550001	Accum Deferred ITC - Federal	5,076,627	4,661,859	574,322	5,236,181	(5,236,181)	(1)	0
177	2570001	Unamort Gn Reacq Debt - FMB	13,529	13,529	1,994	15,523	(15,523)	(1)	0
178	2811001	Acc Dfd FIT - Accel Amort Prop	67,837,972	68,316,218	(4,734,676)	63,581,542	(63,581,542)	(1)	0
179	2814001	Acc Dfd FIT - FAS 109 Excess	(26,962,712)	(27,152,794)	184,780	(26,968,014)	26,968,014	(1)	0
180	2821001	Accum Defd FIT - Utility Prop	1,372,305,079	1,381,979,593	(10,509,406)	1,371,470,187	(1,371,470,187)	(1)	0
181	2823001	Acc Dfrd FIT FAS 109 Flow Thru	55,054,998	55,443,126	(249,318)	55,193,808	(55,193,808)	(1)	0
182	2824001	Acc Dfrd FIT - SFAS 109 Excess	(540,222,908)	(544,031,386)	1,051,798	(542,979,588)	542,979,588	(1)	0
183	2831001	Accum Deferred FIT - Other	32,930,400	33,162,554	7,374,092	40,536,646	(40,536,646)	(1)	0
184	2831002	Accum Deferred SIT - Other	0	0	0	0			0
185	2832001	Accum Dfrd FIT - Oth Inc & Ded	0	0	0	0			0
186	2833001	Acc Dfd FIT FAS 109 Flow Thru	54,730,848	55,116,691	(389,373)	54,727,318	(54,727,318)	(1)	0
187	2833002	Acc Dfrd SIT FAS 109 Flow Thru	191,121,231	192,468,603	(1,538,935)	190,929,668	(190,929,668)	(1)	0
188	2834001	Acc Defd FIT - SFAS 109 Exces	8,888,986	8,951,652	(51,962)	8,899,690	(8,899,690)	(1)	0
189									
190			2,816,657,174	2,674,170,684	67,408,945	2,741,579,629	(1,768,075,562)		973,504,066
191			(A)	(A)					(A) (B)

192 Supporting Schedules — Recap Schedules
193 * Include one of the following reference numbers for each adjustment: — (a) Schedule D-6.2 — (A) WP D-1-1
194 (1) Provided for elsewhere in the Cost of Service — (B) D-1.3
195 (2) Interest-Bearing
196 (3) 13-Month Average is not representative of normal account balance
197 (4) Netted with Asset Balance
198 (5) 100% other jurisdiction
199 (6) Provided in Accum Res for Depr Schd B-2
200 (7) Turk adjustment

Southwestern Electric Power Company
Adjustment to Working Capital Liabilities to Remove Turk Plant
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP D-6.1

Line No.	Account		2017 Dec	2018 Jan	Feb	Mar	Apr	May	Jun	Jul	Projected Aug	Projected Sep	Projected Oct	Projected Nov	Projected Dec	13-Month Average
1	2320011 [1]	Uninvoiced Fuel	########	########	########	########	########	########	########	########	########	(2,284,975)	########	########	########	(1,956,960)
2	2320077 [1]	INDUS Unvouchered Liabilities	322,006	392,642	281,296	378,151	110,076	432,987	403,921	385,843	340,475	285,691	285,691	285,691	285,691	322,320
3	2360004	FICA	(23,946)	(30,603)	(31,416)	(12,803)	(17,100)	(22,049)	(23,916)	(29,582)	(30,594)	(31,328)	(26,224)	(24,365)	(12,865)	(24,368)
4	2360005	Federal Unemployment Tax	(1,875)	(3,984)	(4,004)	(4,056)	(29)	(50)	(86)	(45)	(47)	(48)	(40)	(37)	(20)	(1,102)
5	2360006	State Unemployment Tax	(2,337)	(4,229)	(4,220)	(4,290)	(35)	(55)	(90)	(50)	(52)	(53)	(44)	(41)	(22)	(1,194)
6	2360007	State Sales and Use Taxes	(299,882)	(309,991)	(267,623)	(201,940)	(187,819)	(85,650)	(115,052)	(108,503)	(112,214)	(114,906)	(96,187)	(89,366)	(47,186)	(156,640)
7	2360008	Real Personal Property Taxes	########	########	########	########	########	########	########	########	########	(6,012,390)	########	########	########	(5,344,818)
8	2360037 [1]	FICA - Incentive accrual	(39,014)	(50,826)	(55,626)	(14,267)	(18,460)	(24,121)	(29,042)	(38,964)	(45,114)	(52,155)	(52,155)	(52,155)	(52,155)	(40,312)
9	2410002	State Income Tax Withheld	(11,326)	(11,201)	(11,428)	(27,123)	(13,021)	(16,349)	(11,240)	(11,688)	(11,688)	(11,688)	(11,688)	(11,688)	(11,688)	(13,217)
10	2410003	Local Income Tax Withheld	(22)	(10)	(10)	(10)	-	-	-	(0)	-	-	-	-	-	(4)
11	2410005	FICA Tax Withheld	-	-	-	-	-	(705)	-	-	-	-	-	-	-	(54)
12	2420002	P/R Ded - Medical Insurance	(22,930)	(22,771)	(22,683)	(22,909)	(22,834)	(22,831)	(22,844)	(22,817)	(22,918)	(23,020)	(23,121)	(23,223)	(23,324)	(22,940)
13	2420003	P/R Ded - Dental Insurance	(2,738)	(2,765)	(2,763)	(2,771)	(2,762)	(2,769)	(2,780)	(2,765)	(2,778)	(2,790)	(2,802)	(2,814)	(2,827)	(2,779)
14	2420013	P/R Ded - LTD Ins Premiums	(303)	(336)	(336)	(336)	(336)	(337)	(330)	(329)	(330)	(332)	(333)	(335)	(336)	(332)
15	2420020 [1]	Vacation Pay - This Year	-	(763,580)	(744,451)	(690,202)	(651,815)	(629,516)	(561,131)	(491,952)	(420,529)	(386,887)	(386,887)	(386,887)	(386,887)	(500,056)
16	2420021 [1]	Vacation Pay - Next Year	(865,911)	(104,155)	(137,453)	(188,673)	(239,703)	(296,559)	(328,318)	(387,402)	(452,184)	(512,807)	(512,807)	(512,807)	(512,807)	(388,584)
17	2420027	FAS 112 Current Liability	(80,353)	(80,353)	(80,353)	(96,499)	(96,499)	(96,499)	(96,499)	(96,499)	(96,929)	(97,358)	(97,787)	(98,216)	(98,645)	(93,269)
18	2420051	Non-Productive Payroll	(34,474)	(26,073)	(16,585)	(6,267)	(15,885)	(6,759)	(27,235)	(29,530)	(29,662)	(29,793)	(29,924)	(30,056)	(30,187)	(24,033)
19	2420071	P/R Ded - Vision Plan	(1,078)	(1,098)	(1,096)	(1,100)	(1,099)	(1,099)	(1,103)	(1,099)	(1,104)	(1,108)	(1,113)	(1,118)	(1,123)	(1,103)
20	2420072	P/R - Payroll Adjustment	-	(9)	(9)	(9)	(9)	(9)	(201)	(155)	(155)	(156)	(157)	(157)	(158)	(91)
21	2420076	P/R Savings Plan - Incentive	(21,452)	(23,661)	(26,054)	(6,535)	(8,718)	(10,904)	(15,047)	(17,884)	(17,964)	(18,043)	(18,123)	(18,202)	(18,282)	(16,990)
22	2420618 [1]	Accrued Payroll	(352,851)	(452,304)	(449,944)	(173,120)	(208,742)	(316,680)	(346,223)	(411,566)	(171,408)	(174,399)	(174,399)	(174,399)	(174,399)	(275,418)
23	2420635	Generation Incentive Plan	(212,578)	(235,334)	(257,881)	(67,807)	(90,389)	(113,012)	(153,840)	(182,518)	(183,330)	(184,142)	(184,953)	(185,765)	(186,577)	(172,163)
24	2530112 [1]	Other Deferred Credits-Curr	(74,102)	(74,102)	(74,102)	(74,102)	(74,102)	(74,102)	(74,102)	(74,102)	(74,102)	(74,102)	(74,102)	(74,102)	(74,102)	(74,102)
25		Total														(8,788,208)

Note:
[1] Sourced directly from Company's actual and forecast data based on Turk's department values 12810, 12901, 12902, 12903,12959,13141. Additional supporting workpapers provided electronically.

Recap Schedules
[1] Schedule D-6.1

Southwestern Electric Power Company
Turk Plant Liability Adjustment Support
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP D-6.1-1

Line No	(1)	(2)	(3) Account	(4) Description	(5) Actual 12/31/17	(6) Actual 1/31/18	(7) Actual 2/28/18	(8) Actual 3/31/18	(9) Actual 4/30/18	(10) Actual 5/31/18	(11) Actual 6/30/18	(12) Actual 7/31/18	(13) Forecast 8/31/18	(14) Forecast 9/30/18	(15) Forecast 10/31/18	(16) Forecast 11/30/18	(17) Forecast 12/31/18	(18) 13-month Average
1		Total SWEPCo [a]	2360004	FICA	(374,733)	(478,917)	(491,633)	(200,364)	(267,597)	(345,048)	(374,261)	(462,940)	(478,772)	(490,260)	(410,391)	(381,289)	(201,321)	(381,348)
2	SWEPCo [b]	Turk [b]	Allocation based on payroll expenses															
3	123,399,067	7,885,273																
4	6.390059%	Payroll percentage																
5		Turk		FICA	$ (23,946)	$ (30,603)	$ (31,416)	$ (12,803)	$ (17,100)	$ (22,049)	$ (23,916)	$ (29,582)	$ (30,594)	$ (31,328)	$ (26,224)	$ (24,365)	$ (12,865)	$ (24,368)
6																		
7		Total SWEPCo [a]	2360005	Federal Unemployment Tax	(29,341)	(62,348)	(62,658)	(63,477)	(450)	(777)	(1,352)	(708)	(732)	(750)	(628)	(583)	(308)	(17,239)
8	6.39%	Payroll percentage																
9		Turk	2360005	Federal Unemployment Tax	$ (1,875)	$ (3,984)	$ (4,004)	$ (4,056)	$ (29)	$ (50)	$ (86)	$ (45)	$ (47)	$ (48)	$ (40)	$ (37)	$ (20)	$ (1,102)
10																		
11		Total SWEPCo [a]	2360006	State Unemployment Tax	(36,579)	(66,185)	(66,039)	(67,137)	(545)	(856)	(1,416)	(780)	(806)	(826)	(691)	(642)	(339)	(18,680)
12	6.39%	Payroll percentage																
13		Turk	2360006	State Unemployment Tax	$ (2,337)	$ (4,229)	$ (4,220)	$ (4,290)	$ (35)	$ (55)	$ (90)	$ (50)	$ (52)	$ (53)	$ (44)	$ (41)	$ (22)	$ (1,194)
14																		
15		Total SWEPCo [a]	236000700	State Sales and Use Taxes	(311,500)	(311,500)	(325,500)	-	-	-	-	-	-	-	-	-	-	(72,962)
16			236000716	State Sales and Use Taxes	-	-	-	(0)	-	-	-	-	-	-	-	-	-	(0)
17			236000717	State Sales and Use Taxes	(2,132,071)	(199,755)	(375,302)	14,794	14,794	179,766	179,766	263,277	272,280	278,813	233,391	216,841	114,492	(72,224)
18			236000718	State Sales and Use Taxes	-	(2,014,689)	(1,479,909)	(1,660,291)	(1,545,222)	(877,676)	(1,117,260)	(1,147,409)	(1,186,648)	(1,215,120)	(1,017,163)	(945,033)	(498,980)	(1,131,185)
19	SWEPCo [c]	Turk [d]	Allocation based on major related expenses															
20	21,398,629	976,525	5060000	Misc Steam Power Expenses														
21	6,094,753	785,860	5100000	Maint Supv & Engineering														
22	4,093,958	1,435,609	5110000	Maintenance of Structures														
23	53,208,885	6,897,282	5120000	Maintenance of Boiler Plant														
24	2,102	883	5120025	Maint of Blr Plt Environmental														
25	6,289,299	802,413	5130000	Maintenance of Electric Plant														
26	4,979,079	891,020	5140000	Maintenance of Misc Steam Plt														
27	12.2723%	Based on Related Expenses																
28		Turk	2360007	State Sales and Use Taxes	$ (299,882)	$ (309,991)	$ (267,623)	$ (201,940)	$ (187,819)	$ (85,650)	$ (115,052)	$ (108,503)	$ (112,214)	$ (114,906)	$ (96,187)	$ (89,366)	$ (47,186)	$ (156,640)
29																		
30		Total SWEPCo [a]	236000817	Real Personal Property Taxes	(30,689,410)	(16,182,061)	(15,644,432)	(15,120,873)	(11,290,892)	(11,290,892)	(7,470,471)	(7,475,761)	(7,731,421)	(7,916,925)	(6,627,168)	(6,157,212)	(3,251,023)	(11,296,042)
31			236000818	Real Personal Property Taxes	-	(66,123,082)	(66,123,082)	(66,123,082)	(66,123,082)	(66,123,082)	(64,324,692)	(64,324,692)	(66,524,497)	(68,120,660)	(57,023,030)	(52,979,321)	(27,973,216)	(56,298,886)
32	SWEPCo [c]	Turk [1]	Allocation based on major related expenses															
33	(911,696)	N/A for Turk	408100517	Real Personal Property Taxes														
34	64,201,415	5,004,400 [2]	408100518	Real Personal Property Taxes														
35	7.91%	Based on Related Expenses																
36		Turk	236000817	Real Personal Property Taxes	$ (2,426,651)	$ (6,507,974)	$ (6,465,463)	$ (6,424,065)	$ (6,121,223)	$ (6,121,223)	$ (5,676,936)	$ (5,677,355)	$ (5,871,512)	$ (6,012,390)	$ (5,032,904)	$ (4,676,002)	$ (2,468,941)	$ (5,344,818)
37																		
38		Total SWEPCo [a]	2410002	State Income Tax Withheld	(177,246)	(175,282)	(178,833)	(424,461)	(203,764)	(255,847)	(175,896)	(182,911)	(182,911)	(182,911)	(182,911)	(182,911)	(182,911)	(206,830)
39	6.39%	Payroll percentage																
40		Turk	2410002	State Income Tax Withheld	$ (11,326)	$ (11,201)	$ (11,428)	$ (27,123)	$ (13,021)	$ (16,349)	$ (11,240)	$ (11,688)	$ (11,688)	$ (11,688)	$ (11,688)	$ (11,688)	$ (11,688)	$ (13,217)
41																		
42		Total SWEPCo [a]	2410003	Local Income Tax Withheld	(346)	(161)	(161)	(161)	-	-	-	(0)	-	-	-	-	-	(64)
43	6.39%	Payroll percentage																
44		Turk	2410003	Local Income Tax Withheld	$ (22)	$ (10)	$ (10)	$ (10)	$ -	$ -	$ -	$ (0)	$ -	$ -	$ -	$ -	$ -	$ (4)
45																		
46		Total SWEPCo [a]	2410005	FICA Tax Withheld	-	-	-	-	-	(11,025)	-	-	-	-	-	-	-	(848)
47	6.39%	Payroll percentage																
48		Turk	2410005	FICA Tax Withheld	$ -	$ -	$ -	$ -	$ -	$ (705)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (54)
49																		
50		Total SWEPCo [a]	2420002	P/R Ded - Medical Insurance	(358,843)	(356,356)	(354,974)	(358,508)	(357,338)	(357,297)	(357,499)	(357,067)	(358,655)	(360,243)	(361,831)	(363,419)	(365,007)	(359,003)
51	6.39%	Payroll percentage																
52		Turk	2420002	P/R Ded - Medical Insurance	$ (22,930)	$ (22,771)	$ (22,683)	$ (22,909)	$ (22,834)	$ (22,831)	$ (22,844)	$ (22,817)	$ (22,918)	$ (23,020)	$ (23,121)	$ (23,223)	$ (23,324)	$ (22,940)
53																		

Southwestern Electric Power Company
Turk Plant Liability Adjustment Support
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP D-6.1-1

Line No	(1)	(2)	(3) Account	(4) Description	(5) Actual 12/31/17	(6) Actual 1/31/18	(7) Actual 2/28/18	(8) Actual 3/31/18	(9) Actual 4/30/18	(10) Actual 5/31/18	(11) Actual 6/30/18	(12) Actual 7/31/18	(13) Forecast 8/31/18	(14) Forecast 9/30/18	(15) Forecast 10/31/18	(16) Forecast 11/30/18	(17) Forecast 12/31/18	(18) 13-month Average
54		Total SWEPCo [(a)]	2420003	P/R Ded - Dental Insurance	(42,850)	(43,277)	(43,239)	(43,357)	(43,216)	(43,337)	(43,505)	(43,274)	(43,466)	(43,659)	(43,851)	(44,043)	(44,236)	(43,485)
55	6.39%	Payroll percentage																
56		Turk	2420003	P/R Ded - Dental Insurance	$ (2,738)	$ (2,765)	$ (2,763)	$ (2,771)	$ (2,762)	$ (2,769)	$ (2,780)	$ (2,765)	$ (2,778)	$ (2,790)	$ (2,802)	$ (2,814)	$ (2,827)	$ (2,779)
57																		
58		Total SWEPCo [(a)]	2420013	P/R Ded - LTD Ins Premiums	(4,741)	(5,258)	(5,257)	(5,253)	(5,265)	(5,273)	(5,166)	(5,149)	(5,172)	(5,195)	(5,218)	(5,241)	(5,264)	(5,189)
59	6.39%	Payroll percentage																
60		Turk	2420013	P/R Ded - LTD Ins Premiums	$ (303)	$ (336)	$ (336)	$ (336)	$ (336)	$ (337)	$ (330)	$ (329)	$ (330)	$ (332)	$ (333)	$ (335)	$ (336)	$ (332)
61																		
62		Total SWEPCo [(a)]	2420027	FAS 112 CURRENT LIAB	(1,257,475)	(1,257,475)	(1,257,475)	(1,510,149)	(1,510,149)	(1,510,149)	(1,510,149)	(1,510,149)	(1,516,866)	(1,523,582)	(1,530,299)	(1,537,016)	(1,543,733)	(1,459,590)
63	6.39%	Payroll percentage																
64		Turk	2420027	FAS 112 CURRENT LIAB	$ (80,353)	$ (80,353)	$ (80,353)	$ (96,499)	$ (96,499)	$ (96,499)	$ (96,499)	$ (96,499)	$ (96,929)	$ (97,358)	$ (97,787)	$ (98,216)	$ (98,645)	$ (93,269)
65																		
66		Total SWEPCo [(a)]	2420051	Non-Productive Payroll	(539,493)	(408,024)	(259,540)	(98,071)	(248,590)	(105,779)	(426,209)	(462,130)	(464,186)	(466,241)	(468,296)	(470,352)	(472,407)	(376,102)
67	6.39%	Payroll percentage																
68		Turk	2420051	Non-Productive Payroll	$ (34,474)	$ (26,073)	$ (16,585)	$ (6,267)	$ (15,885)	$ (6,759)	$ (27,235)	$ (29,530)	$ (29,662)	$ (29,793)	$ (29,924)	$ (30,056)	$ (30,187)	$ (24,033)
69																		
70		Total SWEPCo [(a)]	2420071	P/R Ded - Vision Plan	(16,863)	(17,178)	(17,153)	(17,214)	(17,193)	(17,203)	(17,257)	(17,193)	(17,270)	(17,346)	(17,422)	(17,499)	(17,575)	(17,259)
71	6.39%	Payroll percentage																
72		Turk	2420071	P/R Ded - Vision Plan	$ (1,078)	$ (1,098)	$ (1,096)	$ (1,100)	$ (1,099)	$ (1,099)	$ (1,103)	$ (1,099)	$ (1,104)	$ (1,108)	$ (1,113)	$ (1,118)	$ (1,123)	$ (1,103)
73																		
74		Total SWEPCo [(a)]	2420072	P/R - Payroll Adjustment	-	(146)	(146)	(146)	(146)	(146)	(3,145)	(2,420)	(2,431)	(2,441)	(2,452)	(2,463)	(2,474)	(1,427)
75	6.39%	Payroll percentage																
76		Turk	2420072	P/R - Payroll Adjustment	$ -	$ (9)	$ (9)	$ (9)	$ (9)	$ (9)	$ (201)	$ (155)	$ (155)	$ (156)	$ (157)	$ (157)	$ (158)	$ (91)
77																		
78		Total SWEPCo [(a)]	2420076	P/R Savings Plan - Incentive	(335,715)	(370,274)	(407,723)	(102,266)	(136,427)	(170,637)	(235,483)	(279,872)	(281,117)	(282,361)	(283,606)	(284,851)	(286,096)	(265,879)
79	6.39%	Payroll percentage																
80		Turk	2420076	P/R Savings Plan - Incentive	$ (21,452)	$ (23,661)	$ (26,054)	$ (6,535)	$ (8,718)	$ (10,904)	$ (15,047)	$ (17,884)	$ (17,964)	$ (18,043)	$ (18,123)	$ (18,202)	$ (18,282)	$ (16,990)
81																		
82		Total SWEPCo [(a)]	2420635	Generation Incentive Plan	(3,326,699)	(3,682,809)	(4,035,654)	(1,061,132)	(1,414,520)	(1,768,556)	(2,407,492)	(2,856,281)	(2,868,985)	(2,881,689)	(2,894,393)	(2,907,097)	(2,919,801)	(2,694,239)
83	6.39%	Payroll percentage																
84		Turk	2420635	Generation Incentive Plan	$ (212,578)	$ (235,334)	$ (257,881)	$ (67,807)	$ (90,389)	$ (113,012)	$ (153,840)	$ (182,518)	$ (183,330)	$ (184,142)	$ (184,953)	$ (185,765)	$ (186,577)	$ (172,163)

Purpose is to calculate Turk Plant's related share of SWEPCo total liabilities where it was not available directly from ledger or forecasting data.

(1) Tax Department initial estimation based on tax district billed paid in 2018.

(2) Preliminary tax estimate used for Turk of $5,004,400 does not tie to final amount on WP C 2-17-1 in the amount of -----------------------> 5,069,251

Supporting Schedules

[(a)] E-17B
[(b)] WP B 4-4
[(c)] E-17A
[(d)] WP C 2-21-1

Recap Schedule
WP D-6.1-1

Southwestern Electric Power Company
Liability Account Balances
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing balances for all current, accrued, and other liabilities by subaccount for 13 months ending with the last month of the test year This Schedule applies to all liabilities not included in Schedule D-2, D-3, and D-4. Subaccount Description should provide a detailed discussion of the purpos of the subaccount using examples if needed. If full description of subaccounts is provided in E-9, this section may be omitted.

Line No.	Account	Description	Balance 12/31/17	Balance 1/31/18	Balance 2/28/18	Balance 3/31/18	Balance 4/30/18	Balance 5/31/18	Balance 6/30/18
			(a)	(a)	(a)	(a)	(a)	(a)	(a)
1	2270001	Obligatns Undr Cap Lse-Noncurr	22,654,829	22,456,102	22,294,486	22,235,942	23,056,526	23,270,748	23,106,161
2	2270003	Accrued Noncur Lease Oblig	53,544	99,589	113,443	1,236,766	403,673	131,565	107,819
3	2282003	Accm Prv I/D - Worker's Com	108,919	42,656	41,749	53,349	55,655	117,826	114,033
4	2283000	Accm Prv for Pensions&Benefits	1,070,041	1,079,153	1,088,264	1,091,626	1,098,821	1,106,015	1,113,210
5	2283001	Deferred Compensation Plan	1,695,071	1,695,071	1,695,071	1,695,071	1,695,071	1,695,071	1,695,071
6	2283002	Supplemental Savings Plan	1,158,619	1,147,901	1,147,901	1,158,846	1,158,846	1,158,846	1,070,508
7	2283005	SFAS 112 Postemployment Benef	3,587,589	3,587,589	3,587,589	4,042,857	4,042,857	4,042,857	4,042,857
8	2283006	SFAS 87 - Pensions	0	711,385	1,422,770	2,028,940	2,705,253	3,381,566	4,057,879
9	2283007	Perf Share Incentive Plan	1,245,855	3,393,573	1,225,136	0	(0)	(0)	(0)
10	2283013	Incentive Comp Deferral Plan	102,943	102,943	130,533	130,595	130,595	130,595	171,572
11	2283015	FAS 158 SERP Payable Long Term	979,459	979,459	979,459	965,066	965,066	965,066	950,674
12	2283016	FAS 158 Qual Payable Long Term	660,393	660,393	660,393	(592,291)	(592,291)	(592,291)	(1,844,975)
13	2290002	Acc Prv Rate Refnds-Nonassoc	9,676,544	11,650,977	11,219,167	5,124,363	6,062,553	6,888,967	7,717,897
14	2290006	Acc Prv for Potential Refund	2,625,000	4,576,181	2,625,000	0	0	0	0
15	2290018	Acc Prov Refunds - Tax Reform	0	0	8,825,134	11,073,931	13,928,890	17,521,985	24,164,479
16	2290019	Acc Prov Refund-Excess Protect	0	0	0	3,507,508	4,676,677	5,845,846	7,015,016
17	2300001	Asset Retirement Obligations	83,838,275	83,768,134	83,666,783	83,522,050	82,890,494	82,435,941	101,811,098
18	2300002	ARO - Current	8,919,951	8,919,951	8,919,951	8,919,951	8,919,951	8,919,951	12,595,939
19	2320001	Accounts Payable - Regular	48,641,920	45,928,448	43,193,337	31,294,903	33,538,340	27,121,529	26,742,401
20	2320002	Unvouchered Invoices	28,913,937	23,382,094	29,896,479	30,073,727	32,440,281	26,356,119	21,412,467
21	2320003	Retention	4,350,562	4,280,140	5,129,159	5,788,128	6,718,893	7,799,214	7,152,577
22	2320008	Miscellaneous Liabilities	0	0	0	0	0	0	0
23	2320011	Uninvoiced Fuel	21,496,342	29,633,724	23,091,292	17,168,676	11,077,127	18,292,019	22,031,053
24	2320052	Accounts Payable - Purch Power	11,890,048	12,787,234	10,534,205	9,042,403	9,473,562	8,876,728	13,858,532
25	2320054	Emission Allowance Trading	0	(700)	(700)	0	(700)	(700)	46,175
26	2320062	Broker Fees Payable	2,498	3,229	3,230	3,230	2,890	3,515	3,515
27	2320066	A/P - OPEN ACCESS TRANS EXP	11,284,422	10,843,454	11,661,950	11,623,671	11,638,579	11,691,026	11,854,138
28	2320075	Unvouch - Dolet Hills - Cleco	1,326,250	1,400,731	3,625,871	(15,532)	2,004,412	2,318,660	1,491,414
29	2320076	Corporate Credit Card Liab	153,535	268,454	266,966	358,609	272,698	245,576	268,169
30	2320077	INDUS Unvouchered Liabilities	9,331,715	6,410,622	6,139,952	2,481,691	2,423,180	3,195,631	3,082,484
31	2320089	Mattison-Centerpoint Payable	16,884,859	1,319,308	2,767,825	4,223,700	5,505,831	6,733,479	7,943,666
32	2320090	MISO AP Accrual	562,436	890,298	627,378	562,436	232,365	290,026	624,030
33	2330000	Corp Borrow Program (NP-Assoc)	118,680,358	0	0	148,611,785	184,673,602	182,836,469	119,910,261
34	2340001	A/P Assoc Co - InterUnit G/L	33,403,526	24,530,946	20,681,628	32,599,461	18,002,641	25,183,503	38,688,365
35	2340025	A/P Assoc Co - CM Bills	6,836	154	56,950	170,231	260,049	19,020	8,606
36	2340027	A/P Assoc Co - Intercompany	701,828	1,104,828	24,001	740,910	614,300	311	240,126
37	2340029	A/P Assoc Co - AEPSC Bills	20,552,805	12,680,601	11,157,231	11,807,682	12,567,532	12,180,845	12,914,060
38	2340030	A/P Assoc Co - InterUnit A/P	89,074	194,647	114,939	166	88,443	3,697,890	64,647
39	2340032	A/P Assoc Co - Multi Pmts	2,397	2,618	20,388	887	19	1,673	5,331
40	2340033	A/P Assoc Co - Factored A/R	44,153,373	42,973,282	40,119,651	39,994,000	47,792,682	53,222,234	59,181,390
41	2340035	Fleet - M4 - A/P	4,992	10,251	12,205	15,033	24,507	10,480	18,072
42	2340041	A/P Assc Co - Non-InterUnit GL	13,897,955	12,494,836	11,191,740	13,025,694	5,669,082	16,551,719	16,381,833
43	2350001	Customer Deposits-Active	62,112,567	62,283,421	62,490,556	62,867,580	63,163,611	63,804,370	64,008,831
44	2350003	Deposits - Trading Activity	0	0	537,244	12,807	(0)	44,865	16,429
45	2360001	Federal Income Tax	(2,678,011)	(134,492)	451,508	(478,166)	(9,901,046)	(6,183,325)	(10,344,095)
46	236000215	State Income Taxes	(12,320)	(12,320)	(12,320)	(12,320)	(12,320)	(12,320)	(12,320)
47	236000216	State Income Taxes	0	0	0	0	0	0	0
48	236000217	State Income Taxes	4,549	4,549	4,549	4,549	4,549	(845,451)	(845,451)
49	236000218	State Income Taxes	0	739,929	860,872	442,381	113,383	1,522,844	826,322
50	2360004	FICA	374,733	478,917	491,633	200,364	267,597	345,048	374,261
51	2360005	Federal Unemployment Tax	29,341	62,348	62,658	63,477	450	777	1,352
52	2360006	State Unemployment Tax	36,579	66,185	66,039	67,137	545	856	1,416
53	236000700	State Sales and Use Taxes	311,500	311,500	325,500	0	0	0	0
54	236000716	State Sales and Use Taxes	0	0	0	0	0	0	0

Supporting Schedules and Workpapers:
(a) Schedule E 17-B

Recap Schedules:
(A) Schedule D 6.1

western Electric Power Company
ity Account Balances
'ear Ending December 31, 2018
et No. 19-008-U

Account	Description	Balance 7/31/18	Forecasted Balance 8/31/18	Forecasted Balance 9/30/18	Forecasted Balance 10/31/18	Forecasted Balance 11/30/18	Forecasted Balance 12/31/18	13-Months Average Balance 12/31/18
		(a)	(a)	(a)	(a)	(a)	(a)	(a)
2270001	Obligatns Undr Cap Lse-Noncurr	22,886,956	22,886,956	22,886,956	22,886,956	22,886,956	18,931,701	22,495,483
2270003	Accrued Noncur Lease Oblig	99,637	99,637	99,637	99,637	99,637	82,418	209,769
2282003	Accm Prv I/D - Worker's Com	87,519	87,519	87,519	87,519	87,519	87,519	81,485
2283000	Accm Prv for Pensions&Benefits	1,120,278	1,192,827	1,265,377	1,337,926	1,410,475	1,483,024	1,189,003
2283001	Deferred Compensation Plan	1,695,071	1,804,844	1,914,617	2,024,390	2,134,163	2,243,936	1,821,732
2283002	Supplemental Savings Plan	1,059,458	1,128,068	1,196,679	1,265,289	1,333,900	1,402,510	1,183,644
2283005	SFAS 112 Postemployment Benef	4,042,857	4,304,673	4,566,488	4,828,304	5,090,119	5,351,935	4,239,890
2283006	SFAS 87 - Pensions	4,734,192	5,040,779	5,347,365	5,653,951	5,960,538	6,267,124	3,639,365
2283007	Perf Share Incentive Plan	0	0	0	0	0	0	451,120
2283013	Incentive Comp Deferral Plan	135,850	144,648	153,445	162,243	171,041	179,838	142,065
2283015	FAS 158 SERP Payable Long Term	950,674	1,012,239	1,073,805	1,135,370	1,196,936	1,258,502	1,031,675
2283016	FAS 158 Qual Payable Long Term	(1,844,975)	(1,964,455)	(2,083,936)	(2,203,417)	(2,322,897)	(2,442,378)	(1,115,594)
2290002	Acc Prv Rate Refnds-Nonassoc	6,211,117	6,674,024	7,059,016	6,922,531	6,786,046	6,649,561	7,587,905
2290006	Acc Prv for Potential Refund	(0)	0	0	0	0	0	755,860
2290018	Acc Prov Refunds - Tax Reform	29,008,073	31,170,010	32,968,055	32,330,623	31,693,190	31,055,758	20,287,702
2290019	Acc Prov Refund-Excess Protect	8,184,185	8,794,142	9,301,433	9,121,592	8,941,750	8,761,908	5,703,851
2300001	Asset Retirement Obligations	101,333,095	101,425,251	101,518,300	101,612,248	101,707,100	101,802,860	93,179,356
2300002	ARO - Current	12,595,939	12,607,394	12,618,960	12,630,638	12,642,428	12,654,331	10,912,718
2320001	Accounts Payable - Regular	19,812,013	19,812,013	19,812,013	19,812,013	19,812,013	19,812,013	28,871,766
2320002	Unvouchered Invoices	21,336,094	21,336,094	21,336,094	21,336,094	21,336,094	21,336,094	24,653,205
2320003	Retention	7,191,769	7,191,769	7,191,769	7,191,769	7,191,769	7,191,769	6,489,945
2320008	Miscellaneous Liabilities	0	0	0	0	0	0	0
2320011	Uninvoiced Fuel	26,631,678	26,631,678	26,631,678	26,631,678	26,631,678	26,631,678	23,275,408
2320052	Accounts Payable - Purch Power	8,541,661	8,541,661	8,541,661	8,541,661	8,541,661	8,541,661	9,824,052
2320054	Emission Allowance Trading	(1,325)	(1,325)	(1,325)	(1,325)	(1,325)	(1,325)	2,725
2320062	Broker Fees Payable	4,140	4,140	4,140	4,140	4,140	4,140	3,611
2320066	A/P - OPEN ACCESS TRANS EXP	11,671,842	11,671,842	11,671,842	11,671,842	11,671,842	11,671,842	11,586,792
2320075	Unvouch - Dolet Hills - Cleco	1,486,927	1,486,927	1,486,927	1,486,927	1,486,927	1,486,927	1,621,028
2320076	Corporate Credit Card Liab	196,636	196,636	196,636	196,636	196,636	196,636	231,832
2320077	INDUS Unvouchered Liabilities	1,554,784	1,554,784	1,554,784	1,554,784	1,554,784	1,554,784	3,261,075
2320089	Mattison-Centerpoint Payable	8,773,177	8,773,177	8,773,177	8,773,177	8,773,177	8,773,177	7,539,825
2320090	MISO AP Accrual	642,667	642,667	642,667	642,667	642,667	642,667	588,075
2330000	Corp Borrow Program (NP-Assoc)	106,690,962	102,176,076	0	0	0	8,615,140	74,784,204
2340001	A/P Assoc Co - InterUnit G/L	34,865,728	34,865,728	34,865,728	34,865,728	34,865,728	34,865,728	30,944,957
2340025	A/P Assoc Co - CM Bills	31,051	31,051	31,051	31,051	31,051	31,051	54,473
2340027	A/P Assoc Co - Intercompany	218,189	218,189	218,189	218,189	218,189	218,189	364,265
2340029	A/P Assoc Co - AEPSC Bills	15,113,837	15,113,837	15,113,837	15,113,837	15,113,837	15,113,837	14,195,675
2340030	A/P Assoc Co - InterUnit A/P	63,566	63,566	63,566	63,566	63,566	63,566	356,246
2340032	A/P Assoc Co - Multi Pmts	13,582	13,582	13,582	13,582	13,582	13,582	8,831
2340033	A/P Assoc Co - Factored A/R	55,428,382	55,428,382	55,428,382	55,428,382	55,428,382	55,428,382	50,769,762
2340035	Fleet - M4 - A/P	8,250	8,250	8,250	8,250	8,250	8,250	11,157
2340041	A/P Assc Co - Non-InterUnit GL	14,903,072	14,903,072	14,903,072	14,903,072	14,903,072	14,903,072	13,740,869
2350001	Customer Deposits-Active	63,929,187	63,929,187	63,929,187	63,929,187	63,929,187	63,929,187	63,408,158
2350003	Deposits - Trading Activity	(0)	0	0	0	0	0	47,027
2360001	Federal Income Tax	(5,434,102)	(5,619,940)	(5,754,782)	(4,817,263)	(4,475,653)	(2,363,156)	(4,440,963)
236000215	State Income Taxes	(12,320)	(12,741)	(13,047)	(10,922)	(10,147)	(5,358)	(11,598)
236000216	State Income Taxes	0	0	0	0	0	0	0
236000217	State Income Taxes	(845,451)	(874,364)	(895,343)	(749,482)	(696,333)	(367,666)	(468,984)
236000218	State Income Taxes	2,332,721	2,412,497	2,470,381	2,067,928	1,921,284	1,014,443	1,286,537
2360004	FICA	462,940	478,772	490,260	410,391	381,289	201,321	381,348
2360005	Federal Unemployment Tax	708	732	750	628	583	308	17,239
2360006	State Unemployment Tax	780	806	826	691	642	339	18,680
236000700	State Sales and Use Taxes	0	0	0	0	0	0	72,962
236000716	State Sales and Use Taxes	0	0	0	0	0	0	0

Supporting Schedules and Workpapers:
(a) Schedule E 17-B

Recap Schedules:
(A) Schedule D 6.1

Southwestern Electric Power Company
Liability Account Balances
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing balances for all current, accrued, and other liabilities by subaccount for 13 months ending with the last month of the test year
This Schedule applies to all liabilities not included in Schedule D-2, D-3, and D-4. Subaccount Description should provide a detailed discussion of the purpos
of the subaccount using examples if needed. If full description of subaccounts is provided in E-9, this section may be omitted.

Line No.	Account	Description	Balance 12/31/17	Balance 1/31/18	Balance 2/28/18	Balance 3/31/18	Balance 4/30/18	Balance 5/31/18	Balance 6/30/18
55	236000717	State Sales and Use Taxes	2,132,071	199,755	375,302	(14,794)	(14,794)	(179,766)	(179,766)
56	236000718	State Sales and Use Taxes	0	2,014,689	1,479,909	1,660,291	1,545,222	877,676	1,117,260
57	236000816	Real Personal Property Taxes	0	0	0	0	0	0	0
58	236000817	Real Personal Property Taxes	30,689,410	16,182,061	15,644,432	15,120,873	11,290,892	11,290,892	7,470,471
59	236000818	Real Personal Property Taxes	0	66,123,082	66,123,082	66,123,082	66,123,082	66,123,082	64,324,692
60	236001205	State Franchise Taxes	0	0	0	0	0	0	0
61	236001216	State Franchise Taxes	0	0	0	0	0	0	0
62	236001217	State Franchise Taxes	(363,856)	(363,856)	(363,856)	(363,856)	(363,856)	(363,856)	(363,856)
63	236001218	State Franchise Taxes	0	1,404,100	1,404,100	1,404,100	1,167,000	(2,672,000)	(2,672,000)
64	236002016	State Public Service Com Tax	0	0	0	0	0	0	0
65	236002017	State Public Service Com Tax	808,326	928,047	1,047,768	1,077,489	1,197,210	1,316,931	1,436,652
66	236002018	State Public Service Com Tax	0	42,000	84,000	126,000	166,000	206,000	120,000
67	236002206	State License/Registration Tax	0	0	0	0	0	0	0
68	236002208	State License/Registration Tax	0	0	0	0	0	0	0
69	236002516	Local Franchise Tax	0	0	0	0	0	0	0
70	236002517	Local Franchise Tax	3,719,366	0	0	0	0	0	0
71	236002518	Local Franchise Tax	0	1,635,953	2,811,803	3,844,277	1,194,648	2,342,390	3,943,187
72	236003316	Pers Prop Tax-Cap Leases	0	0	0	0	0	0	0
73	236003317	Pers Prop Tax-Cap Leases	97,837	(9,469)	0	0	0	0	0
74	236003318	Pers Prop Tax-Cap Leases	0	173,000	173,000	173,000	173,000	173,000	173,000
75	2360037	FICA - Incentive accrual	624,304	688,604	758,347	190,493	254,793	319,183	440,803
76	2360501	Fed Inc Tax-Short Term FIN48	0	0	0	(247,136)	(247,136)	(247,136)	(247,136)
77	2360502	State Inc Tax-Short Term FIN48	53,646	53,646	53,646	53,646	53,646	53,646	53,646
78	2360601	Fed Inc Tax-Long Term FIN48	(432,721)	(432,721)	(432,721)	0	0	0	432,721
79	2360602	State Inc Tax-Long Term FIN48	(761,734)	(761,734)	(761,734)	(761,734)	(761,734)	(761,734)	(761,734)
80	2360701	SEC Accum Defd FIT-Util FIN 48	0	(0)	(0)	(0)	(0)	(0)	(0)
81	2360702	SEC Accum Defd SIT - FIN 48	(99,070)	(99,070)	(99,070)	(99,070)	(99,070)	(99,070)	(99,070)
82	2360801	Federal Income Tax - IRS Audit	185,585	185,585	185,585	0	0	0	(185,585)
83	2360901	Accum Defd FIT- IRS Audit	1,356,242	1,356,242	1,356,242	1,356,242	1,356,242	1,356,242	0
84	2370002	Interest Accrued-Inst Pur Con	1,722,037	1,702,383	2,110,729	214,000	285,333	356,667	428,000
85	2370005	Interest Accrd-Other LT Debt	56,056	345,676	607,269	62,129	372,773	74,933	396,076
86	2370006	Interest Accrd-Sen Unsec Notes	34,480,350	30,470,767	35,490,558	24,260,350	19,392,642	27,824,933	36,257,225
87	2370007	Interest Accrd-Customer Depsts	1,532,469	117,266	253,105	402,762	546,266	692,756	835,301
88	2370018	Accrued Margin Interest	(0)	(0)	(0)	(0)	(0)	(0)	(0)
89	2370025	Interest Over Recover - AR	0	0	0	0	0	0	0
90	2370348	Acrd Int. - SIT Reserve - LT	2,474	2,474	2,474	3,497	3,497	3,497	88,336
91	2370448	Acrd Int. - SIT Reserve - ST	15,990	15,990	15,990	17,154	17,154	17,154	20,788
92	2380003	Div Decl - Common Stock-Affil	0	0	0	0	0	0	0
93	2410002	State Income Tax Withheld	177,246	175,282	178,833	424,461	203,764	255,847	175,896
94	2410003	Local Income Tax Withheld	346	161	161	161	0	0	0
95	2410004	State Sales Tax Collected	2,342,264	3,930,407	2,884,436	2,734,851	3,239,053	2,669,647	3,740,936
96	2410005	FICA Tax Withheld	0	0	0	0	0	11,025	0
97	2410008	Franchise Fee Collected	3,316,159	1,444,955	2,546,622	3,513,601	1,090,058	2,231,033	3,790,394
98	2420000	Misc Current & Accrued Liab	18,069	18,069	18,069	18,069	18,069	18,069	18,069
99	2420002	P/R Ded - Medical Insurance	358,843	356,356	354,974	358,508	357,338	357,297	357,499
100	2420003	P/R Ded - Dental Insurance	42,850	43,277	43,239	43,357	43,216	43,337	43,505
101	2420007	P/R Ded - Savings Plan	0	59	0	0	0	0	0
102	2420010	P/R Ded - Dependent Life Ins	0	0	0	0	0	0	0
103	2420013	P/R Ded - LTD Ins Premiums	4,741	5,258	5,257	5,253	5,265	5,273	5,166
104	2420016	P/R Ded-Crt Ordr/Grnshmt/Tx Lv	0	0	0	0	0	0	0
105	2420017	P/R Ded - AD&D and OAD&D Ins	0	0	0	0	0	0	0
106	2420018	P/R Ded-Reg&Spec Life Ins Prem	0	0	0	0	0	0	0
107	2420020	Vacation Pay - This Year	0	11,586,505	11,230,994	10,670,078	10,151,882	9,297,815	8,342,194
108	2420021	Vacation Pay - Next Year	12,207,438	1,661,004	2,106,114	2,876,444	3,625,490	4,425,043	4,964,925
109	2420027	FAS 112 CURRENT LIAB	1,257,475	1,257,475	1,257,475	1,510,149	1,510,149	1,510,149	1,510,149
110	2420028	ESP - Employer Contrib Accrued	0	50	0	0	0	0	0

Supporting Schedules and Workpapers:
(a) Schedule E 17-B

Recap Schedules:
(A) Schedule D 6.1

western Electric Power Company
ity Account Balances
'ear Ending December 31, 2018
et No. 19-008-U

Account	Description		Forecasted					13-Months Average
		Balance 7/31/18	Balance 8/31/18	Balance 9/30/18	Balance 10/31/18	Balance 11/30/18	Balance 12/31/18	Balance 12/31/18
236000717	State Sales and Use Taxes	(263,277)	(272,280)	(278,813)	(233,391)	(216,841)	(114,492)	72,224
236000718	State Sales and Use Taxes	1,147,409	1,186,648	1,215,120	1,017,163	945,033	498,980	1,131,185
236000816	Real Personal Property Taxes	0	0	0	0	0	0	
236000817	Real Personal Property Taxes	7,475,761	7,731,421	7,916,925	6,627,168	6,157,212	3,251,023	11,296,042
236000818	Real Personal Property Taxes	64,324,692	66,524,497	68,120,660	57,023,030	52,979,321	27,973,216	56,298,886
236001205	State Franchise Taxes	0	0	0	0	0	0	0
236001216	State Franchise Taxes	0	0	0	0	0	0	0
236001217	State Franchise Taxes	(363,856)	(376,299)	(385,328)	(322,554)	(299,680)	(158,232)	(342,534)
236001218	State Franchise Taxes	(1,505,000)	(1,556,469)	(1,593,814)	(1,334,164)	(1,239,553)	(654,487)	(603,707)
236002016	State Public Service Com Tax	0	0	0	0	0	0	
236002017	State Public Service Com Tax	1,436,652	1,485,783	1,521,433	1,273,574	1,183,260	624,764	1,179,838
236002018	State Public Service Com Tax	291,721	301,697	308,936	258,607	240,268	126,862	174,776
236002206	State License/Registration Tax	0	0	0	0	0	0	0
236002208	State License/Registration Tax	0	0	0	0	0	0	0
236002516	Local Franchise Tax	0	0	0	0	0	0	0
236002517	Local Franchise Tax	0	0	0	0	0	0	286,105
236002518	Local Franchise Tax	1,975,255	2,042,806	2,091,820	1,751,039	1,626,866	858,989	2,009,156
236003316	Pers Prop Tax-Cap Leases	0	0	0	0	0	0	0
236003317	Pers Prop Tax-Cap Leases	8,493	8,783	8,994	7,529	6,995	3,693	10,220
236003318	Pers Prop Tax-Cap Leases	173,000	178,916	183,209	153,362	142,487	75,233	149,554
2360037	FICA - Incentive accrual	524,210	542,137	555,145	464,705	431,751	227,966	463,265
2360501	Fed Inc Tax-Short Term FIN48	(0)	0	0	0	0	0	(76,042)
2360502	State Inc Tax-Short Term FIN48	53,646	55,481	56,812	47,557	44,184	23,329	50,502
2360601	Fed Inc Tax-Long Term FIN48	0	0	0	0	0	0	(66,572)
2360602	State Inc Tax-Long Term FIN48	(761,734)	(787,784)	(806,686)	(675,268)	(627,382)	(331,259)	(717,096)
2360701	SEC Accum Defd FIT-Util FIN 48	0	0	0	0	0	0	(0)
2360702	SEC Accum Defd SIT - FIN 48	(99,070)	(98,929)	(99,196)	(99,395)	(99,587)	(99,768)	(99,187)
2360801	Federal Income Tax - IRS Audit	0	0	0	0	0	0	28,552
2360901	Accum Defd FIT- IRS Audit	0	0	0	0	0	0	625,958
2370002	Interest Accrued-Inst Pur Con	71,333	80,531	77,042	54,332	71,524	88,581	558,653
2370005	Interest Accrd-Other LT Debt	87,640	98,941	94,653	66,751	87,874	108,830	189,200
2370006	Interest Accrd-Sen Unsec Notes	31,789,517	35,888,637	34,333,364	24,212,714	31,874,600	39,475,688	31,211,642
2370007	Interest Accrd-Customer Depsts	979,957	1,106,318	1,058,374	746,391	982,580	1,216,894	805,418
2370018	Accrued Margin Interest	0	0	0	0	0	0	(0)
2370025	Interest Over Recover - AR	0	0	0	0	0	0	
2370348	Acrd Int. - SIT Reserve - LT	88,336	99,727	95,405	67,282	88,572	109,694	50,405
2370448	Acrd Int. - SIT Reserve - ST	20,788	23,469	22,451	15,833	20,844	25,814	19,186
2380003	Div Decl - Common Stock-Affil	0	0	0	0	0	0	0
2410002	State Income Tax Withheld	182,911	182,911	182,911	182,911	182,911	182,911	206,830
2410003	Local Income Tax Withheld	0	0	0	0	0	0	64
2410004	State Sales Tax Collected	4,957,391	4,957,391	4,957,391	4,957,391	4,957,391	4,957,391	3,945,072
2410005	FICA Tax Withheld	0	0	0	0	0	0	848
2410008	Franchise Fee Collected	1,899,362	1,899,362	1,899,362	1,899,362	1,899,362	1,899,362	2,256,076
2420000	Misc Current & Accrued Liab	18,069	18,149	18,230	18,310	18,390	18,471	18,162
2420002	P/R Ded - Medical Insurance	357,067	358,655	360,243	361,831	363,419	365,007	359,003
2420003	P/R Ded - Dental Insurance	43,274	43,466	43,659	43,851	44,043	44,236	43,485
2420007	P/R Ded - Savings Plan	0	0	0	0	0	0	5
2420010	P/R Ded - Dependent Life Ins	3	3	3	3	3	3	1
2420013	P/R Ded - LTD Ins Premiums	5,149	5,172	5,195	5,218	5,241	5,264	5,189
2420016	P/R Ded-Crt Ordr/Grnshmt/Tx Lv	10	10	10	10	10	10	5
2420017	P/R Ded - AD&D and OAD&D Ins	12	12	12	12	12	12	6
2420018	P/R Ded-Reg&Spec Life Ins Prem	23	23	23	24	24	24	11
2420020	Vacation Pay - This Year	7,279,059	7,311,435	7,343,810	7,376,186	7,408,562	7,440,937	8,110,727
2420021	Vacation Pay - Next Year	5,719,633	5,745,073	5,770,512	5,795,952	5,821,391	5,846,831	5,120,450
2420027	FAS 112 CURRENT LIAB	1,510,149	1,516,866	1,523,582	1,530,299	1,537,016	1,543,733	1,459,590
2420028	ESP - Employer Contrib Accrued	0	0	0	0	0	0	4

Supporting Schedules and Workpapers:
(a) Schedule E 17-B

Recap Schedules:
(A) Schedule D 6.1

Southwestern Electric Power Company
Liability Account Balances
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing balances for all current, accrued, and other liabilities by subaccount for 13 months ending with the last month of the test year
This Schedule applies to all liabilities not included in Schedule D-2, D-3, and D-4. Subaccount Description should provide a detailed discussion of the purpos
of the subaccount using examples if needed. If full description of subaccounts is provided in E-9, this section may be omitted.

Line No.	Account	Description	Balance 12/31/17	Balance 1/31/18	Balance 2/28/18	Balance 3/31/18	Balance 4/30/18	Balance 5/31/18	Balance 6/30/18
111	2420046	FAS 158 SERP Payable - Current	150,521	150,521	150,521	150,521	150,521	150,521	150,521
112	2420051	Non-Productive Payroll	539,493	408,024	259,540	98,071	248,590	105,779	426,209
113	2420053	Perf Share Incentive Plan	2,138,758	0	0	1,218,915	1,252,916	1,211,076	1,161,981
114	2420059	MINE CLOSING COSTS - FERC	0	0	0	0	0	0	0
115	2420071	P/R Ded - Vision Plan	16,863	17,178	17,153	17,214	17,193	17,203	17,257
116	2420072	P/R - Payroll Adjustment	0	146	146	146	146	146	3,145
117	2420076	P/R Savings Plan - Incentive	335,715	370,274	407,723	102,266	136,427	170,637	235,483
118	2420081	Environmntl Remediation Accrua	26,137	26,137	26,137	26,137	26,137	26,137	26,137
119	2420083	Active Med and Dental IBNR	274,693	0	0	0	0	0	0
120	2420504	Accrued Lease Expense	151,129	336,548	390,176	571,328	520,747	742,164	173,839
121	2420511	Control Cash Disburse Account	4,868,929	20,691,899	4,143,339	693,423	2,132,220	3,746,240	3,992,715
122	2420512	Unclaimed Funds	28,821	28,821	28,821	29,621	27,589	25,694	19,859
123	2420514	Revenue Refunds Accrued	0	0	0	1,000,000	1,125,000	1,250,000	14,136,852
124	2420519	Provision for Unclaimed Funds	0	0	0	0	0	0	0
125	2420532	Adm Liab-Cur-S/Ins-W/C	89,759	136,710	137,054	122,364	139,980	132,298	138,884
126	242053818	Federal Admin Fee	0	0	0	0	0	0	36,705
127	2420558	Admitted Liab NC-Self/Ins-W/C	270,421	203,163	192,089	239,117	222,489	655,602	628,506
128	242059216	Sales Use Tax - Leased Equip	0	0	0	0	0	0	0
129	242059217	Sales Use Tax - Leased Equip	196	0	0	0	0	0	0
130	242059218	Sales Use Tax - Leased Equip	0	3,577	13,569	2,546	196	2,766	1,791
131	2420618	Accrued Payroll	4,677,241	6,056,079	5,926,040	2,279,381	2,703,441	4,136,576	4,611,856
132	2420623	Distr, Cust Ops & Reg Svcs ICP	4,026,476	4,440,056	4,894,715	1,214,614	1,618,909	2,024,355	2,835,974
133	2420624	Corp & Shrd Srv Incentive Plan	515,265	565,580	629,825	150,156	199,861	250,269	340,626
134	2420635	Generation Incentive Plan	3,326,699	3,682,809	4,035,654	1,061,132	1,414,520	1,768,556	2,407,492
135	2420643	Accrued Audit Fees	7,738	93,139	178,540	275,762	365,104	206,211	52,032
136	2420644	Reclamation Liability - Affil	76,423,070	76,716,948	77,010,826	77,304,704	77,598,582	77,892,460	78,186,338
137	2420649	Reclamation Liability - Curr	2,534	1,307	1,631	2,460	1,708	1,863	1,907
138	2420660	AEP Transmission ICP	756,476	823,210	914,190	198,563	264,751	330,939	448,665
139	2420662	Accrued Railcar Lease Exp - ST	12,687	12,687	12,687	12,687	12,687	12,687	12,687
140	2420663	Accrued railcar lease exp - LT	103,445	101,974	100,502	99,030	97,558	96,087	94,615
141	2420665	Dollar Energy Assistance Pgm	1,711	1,815	1,335	1,395	1,559	1,339	1,421
142	2420700	Quality of Service	0	0	0	0	0	0	212,399
143	2430001	Oblig Under Cap Leases - Curr	4,284,287	4,229,922	4,264,687	4,206,363	4,245,972	4,280,395	4,205,350
144	2430003	Accrued Cur Lease Oblig	9,320	24,827	28,361	142,508	62,886	29,365	26,955
145	2440001	Curr. Unreal Losses - NonAffil	183,288	0	228,058	60,072	1,152,734	7,700	29,805
146	2440002	LT Unreal Losses - Non Affil	4,186	254,503	929,436	547,737	1,624,173	2,065,807	2,267,821
147	2530000	Other Deferred Credits	196,340	193,097	184,743	6,582,134	6,455,512	6,328,891	6,202,269
148	2530022	Customer Advance Receipts	4,185,332	3,700,712	4,026,277	4,846,641	5,571,988	5,533,316	4,368,348
149	2530050	Deferred Rev -Pole Attachments	1,051,209	902,035	727,055	550,081	373,108	196,135	109,191
150	2530067	IPP - System Upgrade Credits	6,804,195	6,825,055	6,845,915	6,846,113	6,872,719	6,895,440	6,916,768
151	2530101	MACSS Unidentified EDI Cash	800	0	17,768	7,071	7,476	6,777	2,738
152	2530104	Railroad Cars Subleased-Rev	0	0	0	0	0	44,532	0
153	2530112	Other Deferred Credits-Curr	594,628	159,854	180,936	165,635	321,376	171,690	173,161
154	2530120	Environ Remediation LT	143,957	143,957	143,957	143,957	143,957	143,957	143,957
155	2530124	Contr In Aid of Constr Advance	452,585	455,671	563,086	434,233	353,639	397,734	338,115
156	2530139	IPP - Aff. Sys Upgrade Credits	0	0	0	0	0	0	0
157	2530181	Oxbow Buy In	2,864,334	2,855,594	2,847,042	2,838,498	2,832,035	2,825,571	2,814,125
158	2530185	O\U Accounting of ExpensesT	0	0	0	174,954	0	0	29,614
159	2530188	Long Term Assoc AP	0	0	0	0	0	0	3,653,778
160	2530190	QUAL OF SVC PENALTIES - LT	0	0	0	100,988	100,988	100,988	0
161	2540047	Unreal Gain on Fwd Commitments	2,842,712	1,601,732	280,317	0	301,484	331,672	298,975
162	2540050	Def Rev Selling Price Variance	0	1,147,001	650,784	0	0	0	0
163	2540052	EXCESS EARNINGS	2,615,476	2,609,476	2,603,476	2,597,476	2,591,476	2,585,476	2,579,476
164	2540058	Dolet Hills Mining Buy-Out	272,906	272,906	272,906	272,906	272,906	272,906	272,906
165	2540090	Over Recovered Fuel Cost - TX	7,494,126	3,500,807	3,854,959	6,404,470	7,247,125	4,740,223	9,135,863
166	2540094	Over Recovered Fuel Cost - LA	1,169,312	2,762	0	0	1,206,824	3,213	2,255,797

Supporting Schedules and Workpapers:
(a) Schedule E 17-B

Recap Schedules:
(A) Schedule D 6.1

western Electric Power Company
ity Account Balances
'ear Ending December 31, 2018
et No. 19-008-U

			Forecasted					13-Months Average
Account	Description	Balance 7/31/18	Balance 8/31/18	Balance 9/30/18	Balance 10/31/18	Balance 11/30/18	Balance 12/31/18	Balance 12/31/18
2420046	FAS 158 SERP Payable - Current	150,521	151,190	151,860	152,529	153,199	153,868	151,293
2420051	Non-Productive Payroll	462,130	464,186	466,241	468,296	470,352	472,407	376,102
2420053	Perf Share Incentive Plan	1,184,551	1,189,819	1,195,088	1,200,357	1,205,625	1,210,894	1,089,998
2420059	MINE CLOSING COSTS - FERC	0	0	0	0	0	0	0
2420071	P/R Ded - Vision Plan	17,193	17,270	17,346	17,422	17,499	17,575	17,259
2420072	P/R - Payroll Adjustment	2,420	2,431	2,441	2,452	2,463	2,474	1,427
2420076	P/R Savings Plan - Incentive	279,872	281,117	282,361	283,606	284,851	286,096	265,879
2420081	Environmntl Remediation Accrua	26,137	26,253	26,369	26,486	26,602	26,718	26,271
2420083	Active Med and Dental IBNR	0	0	0	0	0	0	21,130
2420504	Accrued Lease Expense	360,828	362,433	364,038	365,643	367,247	368,852	390,382
2420511	Control Cash Disburse Account	5,772,907	5,798,584	5,824,260	5,849,937	5,875,614	5,901,290	5,791,643
2420512	Unclaimed Funds	39,554	39,730	39,906	40,082	40,258	40,434	33,015
2420514	Revenue Refunds Accrued	7,489,219	7,522,530	7,555,840	7,589,150	7,622,461	7,655,771	4,842,063
2420519	Provision for Unclaimed Funds	0	0	0	0	0	0	
2420532	Adm Liab-Cur-S/Ins-W/C	150,645	151,315	151,985	152,655	153,325	153,995	139,305
242053818	Federal Admin Fee	0	0	0	0	0	0	2,823
2420558	Admitted Liab NC-Self/Ins-W/C	534,692	537,070	539,448	541,826	544,204	546,583	435,016
242059216	Sales Use Tax - Leased Equip	0	0	0	0	0	0	
242059217	Sales Use Tax - Leased Equip	0	0	0	0	0	0	15
242059218	Sales Use Tax - Leased Equip	3,860	3,877	3,894	3,911	3,929	3,946	3,682
2420618	Accrued Payroll	5,492,497	5,516,926	5,541,356	5,565,785	5,590,214	5,614,644	4,900,926
2420623	Distr, Cust Ops & Reg Svcs ICP	3,376,429	3,391,446	3,406,464	3,421,481	3,436,499	3,451,517	3,195,303
2420624	Corp & Shrd Srv Incentive Plan	404,115	405,912	407,710	409,507	411,304	413,102	392,556
2420635	Generation Incentive Plan	2,856,281	2,868,985	2,881,689	2,894,393	2,907,097	2,919,801	2,694,239
2420643	Accrued Audit Fees	141,373	142,002	142,631	143,260	143,888	144,517	156,631
2420644	Reclamation Liability - Affil	78,480,216	78,829,278	79,178,341	79,527,403	79,876,466	80,225,528	78,250,012
2420649	Reclamation Liability - Curr	813	816	820	824	827	831	1,411
2420660	AEP Transmission ICP	532,033	534,399	536,766	539,132	541,498	543,865	535,730
2420662	Accrued Railcar Lease Exp - ST	12,687	12,744	12,800	12,857	12,913	12,969	12,752
2420663	Accrued railcar lease exp - LT	93,146	93,561	93,975	94,389	94,804	95,218	96,793
2420665	Dollar Energy Assistance Pgm	1,115	1,120	1,125	1,130	1,135	1,140	1,334
2420700	Quality of Service	212,399	213,344	214,288	215,233	216,178	217,123	115,459
2430001	Oblig Under Cap Leases - Curr	4,144,100	3,698,923	3,379,135	2,832,608	2,546,221	6,203,813	4,040,137
2430003	Accrued Cur Lease Oblig	24,909	22,233	20,311	17,026	15,305	37,290	35,484
2440001	Curr. Unreal Losses - NonAffil	212,268	212,268	212,268	212,268	212,268	212,268	225,790
2440002	LT Unreal Losses - Non Affil	2,580,153	2,580,153	2,580,153	2,580,153	2,580,153	2,580,153	1,782,660
2530000	Other Deferred Credits	6,075,648	6,096,080	6,116,512	6,136,944	6,157,376	6,177,808	4,838,720
2530022	Customer Advance Receipts	3,415,040	3,426,524	3,438,009	3,449,493	3,460,978	3,472,462	4,068,855
2530050	Deferred Rev -Pole Attachments	2,182,849	2,190,190	2,197,531	2,204,871	2,212,212	2,219,553	1,316,617
2530067	IPP - System Upgrade Credits	6,943,788	6,967,140	6,990,491	7,013,843	7,037,194	7,060,546	6,924,554
2530101	MACSS Unidentified EDI Cash	2,435	2,443	2,451	2,459	2,467	2,476	4,412
2530104	Railroad Cars Subleased-Rev	(141)	(142)	(142)	(143)	(143)	(144)	3,360
2530112	Other Deferred Credits-Curr	160,777	161,318	161,859	162,400	162,940	163,481	210,773
2530120	Environ Remediation LT	143,957	142,456	140,955	139,454	137,953	136,452	142,225
2530124	Contr In Aid of Constr Advance	318,300	314,981	311,662	308,344	305,025	301,706	373,468
2530139	IPP - Aff. Sys Upgrade Credits	0	0	0	0	0	0	0
2530181	Oxbow Buy In	2,807,662	2,817,104	2,826,546	2,835,988	2,845,430	2,854,872	2,835,754
2530185	O\U Accounting of ExpensesT	(12,043)	(12,083)	(12,124)	(12,164)	(12,205)	(12,245)	10,131
2530188	Long Term Assoc AP	3,654,588	3,666,878	3,679,168	3,691,458	3,703,749	3,716,039	1,981,974
2530190	QUAL OF SVC PENALTIES - LT	0	0	0	0	0	0	23,305
2540047	Unreal Gain on Fwd Commitments	195,847	193,805	191,763	189,721	187,679	185,637	523,180
2540050	Def Rev Selling Price Variance	(0)	0	0	0	0	0	138,291
2540052	EXCESS EARNINGS	2,573,476	2,546,643	2,519,809	2,492,976	2,466,143	2,439,310	2,555,438
2540058	Dolet Hills Mining Buy-Out	272,906	270,060	267,214	264,369	261,523	258,678	269,622
2540090	Over Recovered Fuel Cost - TX	12,424,402	0	0	0	0	0	4,215,537
2540094	Over Recovered Fuel Cost - LA	5,230,602	0	0	0	0	0	759,116

Supporting Schedules and Workpapers:
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Recap Schedules:
(A) Schedule D 6.1

Southwestern Electric Power Company
Liability Account Balances
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing balances for all current, accrued, and other liabilities by subaccount for 13 months ending with the last month of the test year This Schedule applies to all liabilities not included in Schedule D-2, D-3, and D-4. Subaccount Description should provide a detailed discussion of the purpos of the subaccount using examples if needed. If full description of subaccounts is provided in E-9, this section may be omitted.

Line No.	Account	Description	Balance 12/31/17	Balance 1/31/18	Balance 2/28/18	Balance 3/31/18	Balance 4/30/18	Balance 5/31/18	Balance 6/30/18
167	2540118	Energy Efficiency O/U Recovery	0	222,979	246,025	65,683	149,442	247,231	353,979
168	2540137	Over Recovered EAC - LA	0	0	0	0	33,879	0	0
169	2540139	Refundable Construction Int-LA	0	0	0	0	0	0	0
170	2540174	JLStall GR Rider Over Recovery	1,276,748	1,458,014	1,562,349	1,530,915	1,499,593	1,735,409	2,156,539
171	2540184	Texas Vegetation Management	3,088,370	3,694,274	4,214,617	4,590,565	4,623,426	3,440,494	3,224,408
172	2540191	LA SQIP Veg Mgmt O/U Recovery	0	614,722	1,234,765	1,903,733	2,570,399	3,105,033	2,885,264
173	2543001	SFAS109 Flow Thru Def FIT Liab	1,570,017	1,538,512	1,507,007	1,475,502	1,443,997	1,412,493	1,380,988
174	2544001	SFAS 109 Exces Deferred FIT	714,506,058	714,455,894	714,402,730	711,164,290	710,049,368	708,934,445	707,819,522
175	2544009	OCI - Excess DFIT	(1,264,900)	(1,264,900)	0	0	0	0	0
176	2550001	Accum Deferred ITC - Federal	5,906,253	5,787,735	5,669,217	5,550,699	5,432,181	5,313,663	5,195,145
177	2570001	Unamort Gn Reacq Debt - FMB	20,011	19,085	18,159	17,233	16,307	15,381	14,455
178	2811001	Acc Dfd FIT - Accel Amort Prop	67,118,483	40,384,070	40,497,050	67,492,732	67,579,042	67,665,352	67,751,662
179	2814001	Acc Dfd FIT - FAS 109 Excess	(26,847,393)	(26,847,393)	(26,847,393)	(26,962,712)	(26,962,712)	(26,962,712)	(26,962,712)
180	2821001	Accum Defd FIT - Utility Prop	1,366,840,207	1,367,235,482	1,367,460,206	1,366,785,241	1,366,909,905	1,366,854,089	1,372,081,122
181	2823001	Acc Dfrd FIT FAS 109 Flow Thru	55,141,420	55,129,472	55,192,152	55,277,475	55,254,166	55,216,114	55,131,578
182	2824001	Acc Dfrd FIT - SFAS 109 Excess	(546,503,750)	(546,461,750)	(546,419,750)	(543,746,064)	(542,865,275)	(541,984,486)	(541,103,697)
183	2831001	Accum Deferred FIT - Other	72,816,095	61,055,580	60,627,093	33,939,687	33,450,318	33,763,090	33,235,439
184	2831002	Accum Deferred SIT - Other	0	0	0	0	0	0	0
185	2832001	Accum Dfrd FIT - Oth Inc & Ded	0	0	0	0	0	0	0
186	2833001	Acc Dfd FIT FAS 109 Flow Thru	54,362,641	54,355,807	54,371,472	54,775,860	54,824,712	54,822,606	54,714,806
187	2833002	Acc Dfrd SIT FAS 109 Flow Thru	189,260,844	189,243,085	189,238,001	191,055,315	191,317,110	191,354,909	190,948,243
188	2834001	Acc Defd FIT - SFAS 109 Excess	8,891,357	8,888,986	8,888,986	8,888,986	8,888,986	8,888,986	8,888,986
189									
190			2,780,528,083	2,655,521,793	2,644,167,535	2,763,290,124	2,779,984,863	2,817,596,626	2,835,713,665
191	II.	Subaccounts Descriptions							
192									

Supporting Schedules and Workpapers:
(a) Schedule E 17-B

Recap Schedules:
(A) Schedule D 6.1

western Electric Power Company
ity Account Balances
'ear Ending December 31, 2018
et No. 19-008-U

Account	Description	Balance 7/31/18	Forecasted Balance 8/31/18	Balance 9/30/18	Balance 10/31/18	Balance 11/30/18	Balance 12/31/18	13-Months Average Balance 12/31/18
2540118	Energy Efficiency O/U Recovery	594,898	588,695	582,492	576,289	570,087	563,884	366,283
2540137	Over Recovered EAC - LA	0	0	0	0	0	0	2,606
2540139	Refundable Construction Int-LA	0	0	0	0	0	0	
2540174	JLStall GR Rider Over Recovery	2,462,265	2,436,591	2,410,917	2,385,244	2,359,570	2,333,896	1,969,850
2540184	Texas Vegetation Management	2,859,454	2,829,639	2,799,824	2,770,009	2,740,194	2,710,379	3,352,743
2540191	LA SQIP Veg Mgmt O/U Recovery	3,142,610	3,109,843	3,077,075	3,044,308	3,011,540	2,978,773	2,359,851
2543001	SFAS109 Flow Thru Def FIT Liab	1,349,483	1,346,139	1,341,698	1,337,426	1,333,153	1,328,881	1,412,715
2544001	SFAS 109 Exces Deferred FIT	706,704,599	704,953,178	702,627,873	700,390,441	698,153,010	695,915,578	706,928,999
2544009	OCI - Excess DFIT	0	0	0	0	0	0	(194,600)
2550001	Accum Deferred ITC - Federal	5,076,627	4,993,673	4,910,720	4,827,766	4,744,813	4,661,859	5,236,181
2570001	Unamort Gn Reacq Debt - FMB	13,529	13,529	13,529	13,529	13,529	13,529	15,523
2811001	Acc Dfd FIT - Accel Amort Prop	67,837,972	67,741,162	67,924,051	68,060,250	68,192,004	68,316,218	63,581,542
2814001	Acc Dfd FIT - FAS 109 Excess	(26,962,712)	(26,924,234)	(26,996,925)	(27,051,058)	(27,103,425)	(27,152,794)	(26,968,014)
2821001	Accum Defd FIT - Utility Prop	1,372,305,079	1,370,346,704	1,374,046,386	1,376,801,573	1,379,466,842	1,381,979,593	1,371,470,187
2823001	Acc Dfrd FIT FAS 109 Flow Thru	55,054,998	54,976,431	55,124,857	55,235,391	55,342,318	55,443,126	55,193,808
2824001	Acc Dfrd FIT - SFAS 109 Excess	(540,222,908)	(539,451,972)	(540,908,392)	(541,993,002)	(543,042,214)	(544,031,386)	(542,979,588)
2831001	Accum Deferred FIT - Other	32,930,400	32,883,406	32,972,185	33,038,300	33,102,257	33,162,554	40,536,646
2831002	Accum Deferred SIT - Other	0	0	0	0	0	0	
2832001	Accum Dfrd FIT - Oth Inc & Ded	0	0	0	0	0	0	
2833001	Acc Dfd FIT FAS 109 Flow Thru	54,730,848	54,652,743	54,800,296	54,910,179	55,016,477	55,116,691	54,727,318
2833002	Acc Dfrd SIT FAS 109 Flow Thru	191,121,231	190,848,488	191,363,743	191,747,459	192,118,651	192,468,603	190,929,668
2834001	Acc Defd FIT - SFAS 109 Excess	8,888,986	8,876,301	8,900,266	8,918,112	8,935,376	8,951,652	8,899,690
		2,816,657,174	2,801,765,488	2,704,344,325	2,681,562,333	2,685,232,478	2,674,170,684	2,741,579,629
II.	Subaccounts Descriptions							(A)

Supporting Schedules and Workpapers:
(a) Schedule E 17-B

Recap Schedules:
(A) Schedule D 6.1

Southwestern Electric Power Company
Interest Bearing Liabilities' Expense Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE D-6.3

Explanation: Schedule showing the respective cost rate determination and monthly interest expense for each interest-bearing subsccount denoted on Schedules D-6.1 and D-6.2 for the 12 months ending with the last month of the test year.

I. Liability Subaccounts

Line No.	(1) Expense Account No.	(2) Account Title	(3) Description of Interest Rate Determination	(4) 2018 Jan	(5) Feb	(6) Mar	(7) Apr	(8) May	(9) Jun	(10) Jul	(11) Projected Aug	(12) Projected Sep	(13) Projected Oct	(14) Projected Nov	(15) Projected Dec	(16) Test Year Expense	(17) Annual Cost Rate [b]
1	430	Int to Assoc Co - CBP	Corporate Borrowing Program [a]	166,970	-	268,191	366,667	398,090	327,175	252,156	113,671	113,671	-	-	10,159	2,016,750	2.697%
2	431	Interest on Customer Deposits	Regulated by State Commissions [a]	153,816	138,740	154,605	151,023	156,505	154,975	159,311	148,404	143,913	148,018	143,834	152,033	1,805,178	2.847%
3	419	IPP	FERC Rate [c]	24,748	24,748	76	23,106	26,384	25,058	27,960	28,056	26,520	29,653	29,052	29,465	294,826	4.258%
4	Short term/non-recuring																
5	431	Other Interest Expense	Various [c]	-	1,266	2,502	3,652	4,659	5,869	6,923	7,782	8,671				41,324	0.159%
6	431	Mine Reclamation	Regulated by State Commissions [a]	177,740	179,173	180,608	182,052	183,519	185,012	186,522	159,603	160,324	161,177	161,956	162,744	2,080,429	2.659%
7		Total Interest on Interest Bearing Liabilities' Expense		523,274	343,926	605,982	726,500	769,156	698,089	632,872	457,516	453,100	338,848	334,842	354,401	6,238,507	

NOTE:
Annual cost shown is derived by dividing annual expense by the 13 mo. Avg balance
not used to determine rates for future periods See workpapaer D-1-6

Supporting Schedules and Workpapers:
[a] E-17A
[b] Schedule D-6.2
[c] WP D-6.3

Recap Schedules

Southwestern Electric Power Company **WP D-6.3**
Misc. Interest Expense Support
Test Year Ending December 31, 2018
Docket No. 19-008-U

Other interest expense sourced from Company accounting system.
Interest support for IPP Credits (A)

Account	Period	Year	Sum Amount	Long Descr	Line Descr	Journal ID	Unit	Cost Comp
4190002	1	2018	24,673.08	DECEMBER 2017 JOINT OWNER CREDIT AND INTEREST	TURK JT OWNER INTEREST ESTIMA	TURK_JTOWN	168	999
4190002	1	2018	24,747.91	JANUARY 2018 JOINT OWNER CREDIT AND INTEREST ESTIMATE	TURK JT OWNER INTEREST ESTIMA	TURK_JTOWN	168	999
4190002	1	2018	(24,673.08)	DECEMBER 2017 JOINT OWNER CREDIT AND INTEREST ESTIMATE	TURK JT OWNER INTEREST ESTIMA	TURK_JTOWN	168	999
4190002	2	2018	24,747.91	FEBRUARY 2018 JOINT OWNER CREDIT AND INTEREST	TURK JT OWNER INTEREST ESTIMA	TURK_JTOWN	168	999
4190002	3	2018	24,823.88	MARCH 2018 JOINT OWNER CREDIT AND INTEREST	TURK JT OWNER INTEREST ESTIMA	TURK_JTOWN	168	999
4190002	3	2018	(24,747.91)	Reversal of JANUARY 2018 JOINT OWNER CREDIT AND INTEREST ESTIMAT	TURK JT OWNER INTEREST ESTIMA	TURK_JTOWN	168	999
4190002	4	2018	23,105.77	APRIL 2018 JOINT OWNER CREDIT AND INTEREST	TURK JT OWNER INTEREST ESTIMA	TURK_JTOWN	168	999
4190002	5	2018	26,384.04	April 2018 JOINT OWNER CREDIT AND INTEREST	TURK JT OWNER INTEREST ESTIMA	TURK_JTOWN	168	999
4190002	6	2018	25,057.81	May 2018 JOINT OWNER CREDIT AND INTEREST	TURK JT OWNER INTEREST ESTIMA	TURK_JTOWN	168	999
4190002	7	2018	27,959.76	July 2018 JOINT OWNER CREDIT AND INTEREST	TURK JT OWNER INTEREST ESTIMA	TURK_JTOWN	168	999
4190002	8	2018	28,055.85	AUGUST 2018 TURK IPP JOINT OWNER CREDIT AND INTEREST	TURK JT OWNER INTEREST	TURK_JTOWN	168	999
4190002	9	2018	26,520.40	SEPTEMBER 2018 TURK IPP JOINT OWNER CREDIT AND INTEREST	TURK JT OWNER INTEREST	TURK_JTOWN	168	999
4190002	10	2018	29,653.32	October 2018 TURK IPP JOINT OWNER CREDIT AND INTEREST	TURK JT OWNER INTEREST	TURK_JTOWN	168	999
4190002	11	2018	29,051.64	November 2018 TURK IPP JOINT OWNER CREDIT AND INTEREST	TURK JT OWNER INTEREST	TURK_JTOWN	168	999
4190002	12	2018	29,465.37	December 2018 TURK IPP JOINT OWNER CREDIT AND INTEREST	TURK JT OWNER INTEREST	TURK_JTOWN	168	999
			294,825.75					

Interest support for other interest expense

Account	Mo	Yr	Sum Amount	Header Long Descr	Line Descr	Journal ID	Unit	Cost Comp
4310001	2	2018	1,265.96	To record income tax refund provision due to income tax rate change effective 1/2	Other Interest Expense	FCTXTAX	168	REV
4310001	3	2018	2,502.07	To record income tax refund provision due to income tax rate change effective 1/2	Other Interest Expense	FCTXTAX	168	REV
4310001	4	2018	3,651.79	To record income tax refund provision due to income tax rate change effective 1/2	Other Interest Expense	FCTXTAX	168	REV
4310001	5	2018	4,658.64	To record income tax refund provision due to income tax rate change effective 1/2	Other Interest Expense	FCTXTAX	168	REV
4310001	6	2018	5,868.76	To record income tax refund provision due to income tax rate change effective 1/2	Other Interest Expense	FCTXTAX	168	REV
4310001	7	2018	6,922.76	To record income tax refund provision due to income tax rate change effective 1/2	Other Interest Expense	FCTXTAX	168	REV
4310001	8	2018	7,782.42	To record income tax refund provision due to income tax rate change effective 1/2	Other Interest Expense	FCTXTAX	168	REV
4310001	9	2018	8,671.30	To record income tax refund provision due to income tax rate change effective 1/2	Other Interest Expense	FCTXTAX	168	REV

Supporting Schedules:

Recap schedules:
D-6.3

Southwestern Electric Power Company — **Schedule D-7**
Advances for Construction and Contributions in Aid of Construction
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: List of outstanding advances for construction and contributions in aid of construction at end of the historical portion of the test year and explanation of company policy.

I. List of Advances For Construction.

(1) Subaccount Number	(2) Subaccount Title	(3) Advance by or Customer's Account No.	(4) Amount	(5) Date Recorded	(6) Scheduled Refund Date
None					

II. Explain company policy for requiring, holding, and returning advances for construction.

Customer advances are required for construction of facilities where the annual revenue received by the company fails to justify the entire expenditure. Advances remain in the liability account 252 for a period of no more than 5 years. If within this time frame additional revenue is received from the expenditure than some or all of the advance is refunded to the customer. Any remaining balance in the liability account shall be credited to the respective plant account upon contract termination.

III. Total contributions in Aid of Construction.

(1) Account	(2) Deacription	(3) Test Year	(4) Additions	(5) Retirements	(6) Other	(7) Balance at End of Test Year (Historical Period)(1)
101/106	Plant in Service/Completed Construction Not Classified	$ (54,369,130)	$ (1,314,055)	$ 138,476	$ -	$ (55,544,710)
	Total	$ (54,369,130)	$ (1,314,055)	$ 138,476	$ -	$ (55,544,710)

(1) - CIAC obtained directly from Company's fixed asset system these amounts are included in plant in-service balances.

IV. Explain company policy for reacquiring contributions in aid of construction.

Customer payments are required for construction of facilities where the annual revenue received by the company fails to justify the entire expenditure; or where the facilities to be installed are in addition to or non-standard from those normally installed for the type of service to be installed.

Supporting Schedules and Workpapers:

(A) **Recap Schedules:**

American Electric Power Company, Inc.
Index - Holding Company D Workpapers
Test Year Ending December 31, 2018
Docket No. 19-008-U

American Electric Power Company, Inc.
Cost of Capital - Projected Test Year
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE D-1.2 HC

		Projected Test Year as of 12/31/2018					
(1) Line No.	(2) Description	(3) Amount Per Books	(4) Adjustments for Projected Portion of Test Year	(5) Amount Projected Test Year (a)	(6) Proportion (Amount/Total)	(7) Rate %(b)	(8) Weighted Rate %
1	Long Term Debt	$ 1,263,734,532	$ 994,334,374	$ 2,258,068,907	10.29%	4.09%	0.42%
2	Common Equity	18,932,198,323	141,398,323	$ 19,073,596,646	86.89%	10.50%	9.12%
3	Accumulated Deferred Income Taxes	(26,778,625)	877,534	$ (25,901,092)	-0.12%	0.00%	0.00%
4	Short Term/Interim Debt	1,077,775,496	(489,440,585)	$ 588,334,910	2.68%	2.83%	0.08%
5	Current, Accrued and Other Liabilities	130,327,644	(74,196,099)	$ 56,131,545	0.26%	0.00%	0.00%
6	Totals	**$ 21,377,257,370**	**$ 572,973,546**	**$ 21,950,230,917**	**100%**		**9.62%**

Supporting Schedules and Workpapers:
(a) Schedule E-1 HC, Schedule E-17B HC
(b) Schedule D-2.3 HC, WP D-1.1 HC
(c)

Recap Schedule

American Electric Power Company, Inc.
Cost of Short-Term Debt
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP D-1.1 HC

	Rate	*Source*
7/31/2018	2.34%	*cash management*
12/31/2018	2.83%	*UI model EEI Version (forecast model)*
12/31/2019	3.36%	*UI model EEI Version (forecast model)*

Supporting Schedules and Workpapers:

Recap Schedule
D-1.2 HC
D-1.3 HC

American Electric Power Company, Inc.
Cost of Capital- Pro Forma Test Year
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE D-1.3 HC

		Per Books Test Year as of 12/31/2019					
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Description	Amount Beginning of Pro Forma Year (a)	Pro Forma Adjustments(b)	Amount End of Pro Forma Year	Proportion (Amount/Total)	Rate % (b)	Weighted Cost % (Col.6 x Col.7)
1	Long Term Debt	$ 2,258,068,907	$ 797,319,167	$ 3,055,388,074	12.98%	4.09%	0.53%
2	Common Equity	19,073,596,646	755,113,183	$ 19,828,709,829	84.27%	10.50%	8.85%
3	Accumulated Deferred Income Taxes	(25,901,092)	1,329,964	$ (24,571,128)	-0.10%	0.00%	0.00%
4	Short Term/Interim Debt	588,334,910	26,869,318	$ 615,204,228	2.61%	3.36%	0.09%
5	Current, Accrued and Other Liabilities	56,131,545	-	$ 56,131,545	0.24%	0.00%	0.00%
6	Totals	**$ 21,950,230,917**	**$ 1,580,631,632**	**$ 23,530,862,549**	**100.00%**		**9.47%**

Supporting Schedules and Workpapers:
(a) Schedule D-1.2 HC
(b) D-2.3 HC, WP D-1.1 HC

American Electric Power Company, Inc.
Cost of Long Term Debt - Projected Test Year
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE D-2.2 HC

Projected Test Year as of 12/31/2018- Long-Term Debt by Issue Including Current Maturities

(1) Line No.	(2) Description of Debt	(3) Issue Date	(4) Maturity Date	(5) Amount Outstanding per Per Books 7/31/2018 (a)	(6) Unamortized Net Disc/Prem/Exp, Gain/Loss on Reacquired Debt Accts (a)	(7) Net Proceeds (Col. 5 +/- Col. 6)	(8) Adjustments for Projected Portion of Text Year (a)	(9)(b) Net Proceeds Projected Test Year (Col. 7 +/- Col. 8)	(10) Stated Rate %	(11) Annual Interest (Col. 5 x Col. 11)	(12) Projected Amortization Net Disc/Prem & Expense(a)	(13) Projected Annual Cost (Col. 12 +/- Col. 13)
1	Senior Unsecured Notes, Series F	12/3/2012	12/15/2022	300,000,000	(1,220,389)	298,779,611	117,345	298,896,957	2.95%	8,850,000	117,345	8,967,345
2	Senior Unsecured Notes, Series G	11/13/2017	11/13/2020	500,000,000	(2,538,330)	497,461,670	420,802	497,882,472	2.15%	10,750,000	420,802	11,170,802
3	Senior Unsecured Notes, Series H	11/13/2017	11/13/2027	500,000,000	(4,517,571)	495,482,429	241,783	495,724,212	3.20%	16,000,000	241,783	16,241,783
4	Senior Unsecured Notes, Series (Nov 2018)	11/1/2018	11/1/2028	-		-	993,553,039	993,553,039	4.35%	43,500,000	2,520,620	46,020,620
5	Other				(24,753)	(24,753)	1,406	(23,347)				
6	FAS 133 - Swap to Floating	11/13/2017	11/13/2027		(27,964,425)	(27,964,425)	-	(27,964,425)			3,107,158	3,107,158
7	Total			1,300,000,000	(36,265,468)	1,263,734,532	994,334,374	2,258,068,907		79,100,000	6,407,708	
8	Total long term debt interest expense											$ 85,507,708
								2,258,068,907	(c)			
9	Long-Term Debt Cost Col 13/Col 9									Long-Term Debt Cost Col 13/Col 9		3.79%

Supporting Schedules and Workpapers:
(a) WP D-2.3 HC
(b) D-2.3 HC
(c) E-1 HC

Recap Schedules
(A) Schedule D-1.2 HC

American Electric Power Company, Inc.
Cost of Long Term Debt - Pro Forma Year
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE D-2.3 HC

Projected Test Year as of 12/31/2019- Long-Term Debt by Issue Including Current Maturities

(1) Line No.	(2) Description of Debt	(3) Issue Date	(4) Maturity Date	(5) Amount Outstanding per Per Books 7/31/2018 (a)	(6) Unamortized Net Disc/Prem/Exp, Gain/Loss on Reacquired Debt Accts (a)	(7) Net Proceeds (Col. 5 +/- Col. 6)	(8) Adjustments for Projected Portion of Text Year	(9) Net Proceeds Projected Test Year (Col. 7 +/- Col. 8)	(10) Stated Rate %	(11) Annual Interest (Col. 5 x Col. 11)	(12) Projected Amortization Net Disc/Prem & Expense	(13) Projected Annual Cost (Col. 12 +/- Col. 13)
1	Senior Unsecured Notes, Series F	12/3/2012	12/15/2022	300,000,000	(1,103,043)	298,896,957	281,628	299,178,585	2.95%	8,850,000	281,628	9,131,628
2	Senior Unsecured Notes, Series G	11/13/2017	11/13/2020	500,000,000	(2,117,528)	497,882,472	1,009,924	498,892,396	2.15%	10,750,000	1,009,924	11,759,924
3	Senior Unsecured Notes, Series H	11/13/2017	11/13/2027	500,000,000	(4,275,789)	495,724,212	580,278	496,304,490	3.20%	16,000,000	580,278	16,580,278
4	Senior Unsecured Notes, Series (2018)	11/1/2018	11/1/2028	1,000,000,000	(6,446,961)	993,553,039	700,000	994,253,039	4.35%	43,500,000	700,000	44,200,000
5	Senior Unsecured Notes, Series (2019)	11/1/2019	11/1/2029	800,000,000	-		794,803,870	794,803,870	4.90%	39,200,000	520,000	39,720,000
6	Other				(23,347)	(23,347)	(56,533)	(79,880)				
7	FAS 133 - Swap to Floating	11/13/2017	11/13/2027		(27,964,425)	(27,964,425)	-	(27,964,425)			3,495,553	3,495,553
8	Total			3,100,000,000	(41,931,093)	2,258,068,907	797,319,167	3,055,388,074		118,300,000	6,587,383	
9	Total long term debt interest expense											$ 124,887,383
10	Long-Term Debt Cost Col 13/Col 9											4.09%

Supporting Schedules and Workpapers:
(a) WP D-2.3 HC
(b) D-2.2 HC

Recap Schedules
(A) Schedule D-1.2 HC

American Electric Power Company, Inc.
Associated Cost of Debt
Test Year Ending December 31, 2018
Docket No. 19-008-U

Schedule WP D-2.3

Bond Discount - A/C 226	(dr. balance) Balance per Books 31-Jul-18	Amortization Aug-Dec 2018	(dr. balance) **Balance (A) 12/31/2018**	2019 Monthly Amortization	2019 Amortization	**Unamortized 31-Dec-19 Balance**
Series F	(258,700)	24,875	(233,825)	4,975	59,700	(174,125)
Series G	(565,250)	55,417	(509,833)	11,083	133,000	(376,833)
Series H	(722,500)	70,833	(651,667)	14,167	170,000	(481,667)
Other		(23,347)	(23,347)	(4,590)	(55,080)	(78,427)
2018 Bond						
2019 Bond						
Total	(1,546,450)	127,778	(1,418,672)	25,635	307,620	(1,111,052)

Debt Issue Exp. - A/C 181	Balance per Books 31-Jul-18	Amortization Aug-Dec 2018	**Balance 12/31/2018**	2019 Monthly Amortization	2019 Annual Amortization	**Unamortized 31-Dec-19 Balance**
Series F	961,689	(92,470)	869,218	(18,494)	(221,928)	647,290
Series G	1,973,080	(365,385)	1,607,695	(73,077)	(876,924)	730,771
Series H	3,795,071	(170,949)	3,624,122	(34,190)	(410,278)	3,213,844
Other	24,753	(24,753)	0			0
2018 Bond	0	(53,039)	6,446,961	(58,333)	(700,000)	5,746,961
2019 Bond			0	(3,870)	(3,870)	5,196,130
Total	6,754,593	(706,596)	12,547,996	(187,964)	(2,213,000)	15,534,996

2018	1,000,000,000		2019	800,000,000
u/w	0.65%		u/w	0.65%
Tax	6,500,000			5,200,000
Fees	500,000			
Total	7,000,000			
	7/31/2018			

	Balance per Books 31-Jul-18	Amortization Aug-Dec 2018	**Balance 12/31/2018**	2019 Monthly Amortization	2019 Annual Amortization	**Unamortized 31-Dec-19 Balance**
MTM Unrealized Hedging Loss	27,964,425		27,964,425			27,964,425

	Reconcile
Debt per book	1,300,000,000
181 Account	(1,546,450.00)
226 Account	(6,729,839.6)
Hedge MTM	(27,964,425)
	1,263,759,285

Supporting Schedules and Workpapers:

Recap Schedules
(A) Schedule D-2.3 HC
D-2.2 HC

American Electric Power Company, Inc.
Cost of Preferred Stock-Per Projected Test Year
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE D-3.2 HC

(1) Line No.	(2) Description	(3) Issue Date	(4) Amount	(5) Rate %	(6) Dividend Requirement (Col. 4 x Col. 5)	(7) Shares Outstanding
1	No Preferred stock					

Supporting Schedules and Workpapers:

Recap Schedules

American Electric Power Company, Inc.
Cost of Common Equity
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE D-4 HC

Description

N/A for holding company. Please see Schedule D-4

Supporting Schedules and Workpapers:

Recap Schedules

American Electric Power Company, Inc.
Cost of Other Capital Items-Projected Test Year
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE D-5.2 HC

		Projected Test Year as of 12/31/2018			
(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description of Item	Amount Per Books (a) (b)	Adjustments for Projected Portion of Test Year	Amount (a) Projected Test Year (Col. 3 +/- Col. 4)	Rate %
1	Accumulated Deferred Income Taxes	$ (26,778,625)	$ 877,534	$ (25,901,092)	0.00%
2	Short Term/Interim Debt	1,077,775,496	(489,440,585)	588,334,910	2.83%
3	Current, Accrued and Other Liabilities	130,327,644	(74,196,099)	56,131,545	0.00%
4	Totals	$ 1,181,324,515	$ (562,759,151)	$ 618,565,364	
5	Cost Rate				

Supporting Schedules and Workpapers:
(a) Schedule D-1.2 HC
(b) Schedule E-1 HC

Recap Schedules
Schedule D-1.3HC

American Electric Power Company, Inc.
Cost of Other Capital Items-Pro Forma Year
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE D-5.3 HC

		Projected Test Year as of 12/31/2018			
(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description of Item	Amount Beginning Pro Forma Year(a)	Pro Forma Adjustments	Amount (A) End of Pro Forma Year (Col. 3 +/- Col. 4)(a)	Rate %
1	Accumulated Deferred Income Taxes	$ (25,901,092)	$ 1,329,964	$ (24,571,128)	0.00%
2	Short Term/Interim Debt	588,334,910	26,869,318	615,204,228	3.36%
3	Current, Accrued and Other Liabilities	56,131,545	-	56,131,545	0.00%
4	Totals	$ 618,565,364		$ 646,764,646	
5	Cost Rate				

Supporting Schedules and Workpapers:
(a) Schedule D-1.3 HC
(b) Schedule E-1 HC

Recap Schedules
(A) Schedule D-1.3HC

American Electric Power Company, Inc.
Calculation of Current, Accrued and Other Liabilities - Holding Company
Test Year Ending December 31, 2018
Docket No. 19-008-U

Schedule D-6.1 HC

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Account	Account Title	Balance at End of Historic Period(a)	Balance at End of Test Year	Adj. Needed to Achieve 13-Months Average	13-Months Average	Adjustment	Adjustment Reference No.	Pro Forma CAOL(A)
2240006	Senior Unsecured Notes	1,300,000,000	2,287,452,004	(837,054,172)	1,450,397,833	(1,450,397,833)		0
2240007	MTM of LTD - FAS133 FV Hedge	(27,226,313)	(28,644,985)	6,220,471	(22,424,514)	22,424,514		0
2240506	Senior Unsecured Notes-Current	0	0	0	0	0		0
2240507	MTM FAS133 FV Hedge - Current	(738,112)	(738,112)	1,305,030	566,918	(566,918)		0
2260006	Unam Disc LTD-Dr-Sr Unsec Note	(1,546,450)	0	(1,016,762)	(1,016,762)	1,016,762		0
2283001	Deferred Compensation Plan	25,624,141	25,624,141	233,691	25,857,831			25,857,831
2310002	Commercial Paper	1,755,000,000	1,777,233,188	(299,086,907)	1,478,146,281	(1,478,146,281)		0
2320001	Accounts Payable - Regular	1,350,484	1,548,264	(134,325)	1,413,939			1,413,939
2320002	Unvouchered Invoices	197,781	0	673,863	673,863			673,863
2320008	Miscellaneous Liabilities	0	0	1,984	1,984			1,984
2320076	Corporate Credit Card Liab	0	0	37	37			37
2330000	Corp Borrow Program (NP-Assoc)	462,905,535	384,842,686	56,434,192	441,276,877	(441,276,877)		0
2340001	A/P Assoc Co - InterUnit G/L	464,251	1,209,075	5,227,776	6,436,851			6,436,851
2340027	A/P Assoc Co - Intercompany	49,089	0	29,924	29,924			29,924
2340029	A/P Assoc Co - AEPSC Bills	694,306	0	813,404	813,404			813,404
2340030	A/P Assoc Co - InterUnit A/P	1,429	0	901	901			901
2360001	Federal Income Tax	29,616,648	26,521,396	(24,022,985)	2,498,410			2,498,410
2360501	Fed Inc Tax-Short Term FIN48	0	0	1,058,877	1,058,877	(1,058,877)		0
2360601	Fed Inc Tax-Long Term FIN48	0	0	(21,386)	(21,386)	21,386		0
2360801	Federal Income Tax - IRS Audit	0	0	550,824	550,824			550,824

American Electric Power Company, Inc.
Calculation of Current, Accrued and Other Liabilities - Holding Company
Test Year Ending December 31, 2018
Docket No. 19-008-U

Schedule D-6.1 HC

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Account	Account Title	Balance at End of Historic Period(a)	Balance at End of Test Year	Adj. Needed to Achieve 13-Months Average	13-Months Average	Adjustment	Adjustment Reference No.	Pro Forma CAOL(A)
2360901	Accum Defd FIT- IRS Audit	0	0	(1,652,473)	(1,652,473)			(1,652,473)
2370006	Interest Accrd-Sen Unsec Notes	7,232,335	11,073,486	(1,696,656)	9,376,830			9,376,830
2370048	Acrd Int.- FIT Reserve - LT	181,249	0	329,648	329,648			329,648
2420000	Misc Current & Accrued Liab	3,744,594	5,686,587	(1,381,771)	4,304,816			4,304,816
2420511	Control Cash Disburse Account	74	0	165,703	165,703			165,703
2420520	Accr Defer Compensation Ben	358,400	0	199,227	199,227			199,227
2420529	1St Chic-Sharehold Serv-Agent	73,000	0	44,923	44,923			44,923
2420551	Unclaimed Dividends	1,346,851	0	954,418	954,418			954,418
2420643	Accrued Audit Fees	163,668	0	113,662	113,662			113,662
2450017	Deriv-Hdg-Unreal Ls-FV-Int-L/T	27,226,313	27,226,313	(5,421,317)	21,804,996	(21,804,996)		0
2450517	Deriv-Hdg-Unreal Ls-FV-Int-Cur	738,112	738,112	(340,667)	397,445	(397,445)		0
2530000	Other Deferred Credits	5,654,697	0	4,048,846	4,048,846			4,048,846
2530175	Legal Contingencies	(102)	0	(16)	(16)			(16)
2823001	Acc Dfrd FIT FAS 109 Flow Thru	54,521	0	33,085	33,085	(33,085)		0
2830015	ADIT-Fed-Hdg-CF-Int Rate	476,215	0	302,041	302,041	(302,041)		0
2831001	Accum Deferred FIT - Other	(13,688)	0	(7,370)	(7,370)	7,370		0
2833001	Acc Dfd FIT FAS 109 Flow Thru	2,462,185	3,870,454	(997,969)	2,872,485	(2,872,485)		0
2834001	Acc Defd FIT - SFAS 109 Excess	13,688	0	8,423	8,423	(8,423)		0
236000216	State Income Taxes	0	0	0	0			0
236000217	State Income Taxes	(50,050)	0	(30,792)	(30,792)			(30,792)
236001214	State Franchise Taxes	(1,575)	0	(969)	(969)			(969)
236001216	State Franchise Taxes	0	0	0	0			0
236001217	State Franchise Taxes	(400)	0	(246)	(246)			(246)
		3,596,052,875	4,523,642,608	(1,094,115,832)	3,429,526,776	(3,373,395,231)	0	56,131,545

Note: Adjustments relate to other cost of capital.

Supporting Schedules and Workpapers:
(a) D-6.2 HC

Recap Schedules
(A) D-1.2 HC, D-1.3HC

American Electric Power Company, Inc.
Liability Account Balances - Holding Company
Test Year Ending December 31, 2018
Docket No. 19-008-U

Account	Account Title	Actual Dec YTD 2017	Actual Jan YTD 2018	Actual Feb YTD 2018	Actual Mar YTD 2018	Actual Apr YTD 2018	Actual May YTD 2018	Actual Jun YTD 2018
2240006	Senior Unsecured Notes	1,300,000,000	1,300,000,000	1,300,000,000	1,300,000,000	1,300,000,000	1,300,000,000	1,300,000,000
2240007	MTM of LTD - FAS133 FV Hedge	(8,851,317)	(8,851,317)	(8,851,317)	(22,343,875)	(22,343,875)	(22,343,875)	(27,226,313)
2240506	Senior Unsecured Notes-Current	-	-	-	-	-	-	-
2240507	MTM FAS133 FV Hedge - Current	2,458,119	2,458,119	2,458,119	1,720,789	1,720,789	1,720,789	(738,112)
2260006	Unam Disc LTD-Dr-Sr Unsec Note	(1,758,025)	(1,727,800)	(1,697,575)	(1,667,350)	(1,637,125)	(1,606,900)	(1,576,675)
2283001	Deferred Compensation Plan	27,020,547	27,020,547	27,020,547	25,240,394	25,240,394	25,240,394	25,624,141
2310002	Commercial Paper	898,550,000	798,000,000	1,267,000,000	1,886,200,000	1,926,250,000	1,386,250,000	1,814,000,000
2320001	Accounts Payable - Regular	3,332,080	252,520	1,932,799	302,418	217,921	569,214	2,682,448
2320002	Unvouchered Invoices	614,941	690,136	724,299	87,886	4,355,883	1,953,429	135,868
2320008	Miscellaneous Liabilities	25,786	-	-	-	-	-	-
2320076	Corporate Credit Card Liab	381	94	-	-	-	-	-
2330000	Corp Borrow Program (NP-Assoc)	465,144,994	474,407,152	505,762,076	473,803,702	481,399,391	468,514,790	513,735,899
2340001	A/P Assoc Co - InterUnit G/L	774,156	2,021,542	2,588,630	1,633,280	407,278	3,504,525	66,240,026
2340027	A/P Assoc Co - Intercompany	13,562	2,853	14,203	124,368	43,039	32,079	109,812
2340029	A/P Assoc Co - AEPSC Bills	1,506,637	665,235	908,942	5,073,675	483,818	720,034	521,606
2340030	A/P Assoc Co - InterUnit A/P	125	-	-	-	10,164	-	-
2360001	Federal Income Tax	(40,223,907)	(40,223,907)	(40,223,907)	(40,306,041)	(40,278,041)	29,721,959	29,616,648
2360501	Fed Inc Tax-Short Term FIN48	-	-	-	3,441,351	3,441,351	3,441,351	3,441,351
2360601	Fed Inc Tax-Long Term FIN48	(139,007)	(139,007)	(139,007)	-	-	-	139,007

Schedule D-6.2 HC

American Electric Power Company, Inc.
Liability Account Balances - Holding Company
Test Year Ending December 31, 2018
Docket No. 19-008-U

Account	Account Title	Actual Jul YTD 2018	Budget Aug YTD 2018	Budget Sep YTD 2018	Budget Oct YTD 2018	Budget Nov YTD 2018	Budget Dec YTD 2018	13-Months Average
2240006	Senior Unsecured Notes	1,300,000,000	1,293,363,393	1,293,481,379	1,293,599,366	2,287,275,685	2,287,452,004	1,450,397,833
2240007	MTM of LTD - FAS133 FV Hedge	(27,226,313)	(28,747,207)	(28,721,652)	(28,696,096)	(28,670,541)	(28,644,985)	(22,424,514)
2240506	Senior Unsecured Notes-Current	-	-	-	-	-	-	-
2240507	MTM FAS133 FV Hedge - Current	(738,112)	(738,112)	(738,112)	(738,112)	(738,112)	(738,112)	566,918
2260006	Unam Disc LTD-Dr-Sr Unsec Note	(1,546,450)	-	-	-	-	-	(1,016,762)
2283001	Deferred Compensation Plan	25,624,141	25,624,141	25,624,141	25,624,141	25,624,141	25,624,141	25,857,831
2310002	Commercial Paper	1,755,000,000	1,077,979,243	1,387,113,111	1,930,904,964	1,311,421,153	1,777,233,188	1,478,146,281
2320001	Accounts Payable - Regular	1,350,484	1,548,264	1,548,264	1,548,264	1,548,264	1,548,264	1,413,939
2320002	Unvouchered Invoices	197,781	-	-	-	-	-	673,863
2320008	Miscellaneous Liabilities	-	-	-	-	-	-	1,984
2320076	Corporate Credit Card Liab	-	-	-	-	-	-	37
2330000	Corp Borrow Program (NP-Assoc)	462,905,535	376,101,853	379,020,431	376,501,383	374,459,515	384,842,686	441,276,877
2340001	A/P Assoc Co - InterUnit G/L	464,251	1,209,075	1,209,075	1,209,075	1,209,075	1,209,075	6,436,851
2340027	A/P Assoc Co - Intercompany	49,089	-	-	-	-	-	29,924
2340029	A/P Assoc Co - AEPSC Bills	694,306	-	-	-	-	-	813,404
2340030	A/P Assoc Co - InterUnit A/P	1,429	-	-	-	-	-	901
2360001	Federal Income Tax	29,616,648	29,564,623	29,564,621	29,564,621	29,564,621	26,521,396	2,498,410
2360501	Fed Inc Tax-Short Term FIN48	-	-	-	-	-	-	1,058,877
2360601	Fed Inc Tax-Long Term FIN48	-	-	-	-	-	-	(21,386)

American Electric Power Company, Inc.
Liability Account Balances - Holding Company
Test Year Ending December 31, 2018
Docket No. 19-008-U

Account	Account Title	Actual Dec YTD 2017	Actual Jan YTD 2018	Actual Feb YTD 2018	Actual Mar YTD 2018	Actual Apr YTD 2018	Actual May YTD 2018	Actual Jun YTD 2018
2360801	Federal Income Tax - IRS Audit	3,580,358	3,580,358	3,580,358	-	-	-	(3,580,358)
2360901	Accum Defd FIT- IRS Audit	(3,580,358)	(3,580,358)	(3,580,358)	(3,580,358)	(3,580,358)	(3,580,358)	-
2370006	Interest Accrd-Sen Unsec Notes	3,585,740	6,231,283	8,873,022	11,700,984	14,484,382	5,600,724	4,181,161
2370048	Acrd Int.- FIT Reserve - LT	643,822	643,822	643,822	663,818	663,818	663,818	181,249
2420000	Misc Current & Accrued Liab	3,576,056	3,709,091	2,277,126	3,547,694	3,639,062	3,456,325	3,579,726
2420511	Control Cash Disburse Account	232,820	655,784	722,657	220	16,371	176,074	350,143
2420520	Accr Defer Compensation Ben	392,544	392,544	392,544	347,761	347,761	-	358,400
2420529	1St Chic-Sharehold Serv-Agent	73,000	73,000	73,000	73,000	73,000	73,000	73,000
2420551	Unclaimed Dividends	2,045,551	1,362,850	1,218,189	1,981,026	1,348,208	1,218,812	1,885,946
2420643	Accrued Audit Fees	0	96,983	193,966	310,293	413,724	238,732	60,237
2450017	Deriv-Hdg-Unreal Ls-FV-Int-L/T	8,616,379	8,616,379	8,616,379	22,343,875	22,343,875	22,343,875	27,226,313
2450517	Deriv-Hdg-Unreal Ls-FV-Int-Cur	-	-	-	-	-	-	738,112
2530000	Other Deferred Credits	7,427,007	7,270,757	7,114,507	6,608,610	6,452,360	6,296,110	5,810,947
2530175	Legal Contingencies	-	-	-	-	-	-	(102)
2823001	Acc Dfrd FIT FAS 109 Flow Thru	48,463	54,521	54,521	54,521	54,521	54,521	54,521
2830015	ADIT-Fed-Hdg-CF-Int Rate	506,129	499,007	497,582	493,309	489,035	484,762	480,488
2831001	Accum Deferred FIT - Other	-	(13,688)	(13,688)	(13,688)	(13,688)	(13,688)	(13,688)
2833001	Acc Dfd FIT FAS 109 Flow Thru	2,478,621	2,474,951	2,468,592	2,468,691	2,465,915	2,463,963	2,462,185
2834001	Acc Defd FIT - SFAS 109 Excess	13,688	13,688	13,688	13,688	13,688	13,688	13,688
236000216	State Income Taxes	-	-	-	-	-	-	-
236000217	State Income Taxes	(50,025)	(50,025)	(50,025)	(50,025)	(50,050)	(50,050)	(50,050)
236001214	State Franchise Taxes	(1,575)	(1,575)	(1,575)	(1,575)	(1,575)	(1,575)	(1,575)
236001216	State Franchise Taxes	-	-	-	-	-	-	-
236001217	State Franchise Taxes	(400)	(400)	(400)	(400)	(400)	(400)	(400)
		2,678,056,893	2,586,605,139	3,090,591,718	3,680,272,039	3,728,470,635	3,237,156,119	3,770,515,650

Supporting Schedules and Workpapers:
E-17B HC

Schedule D-6.2 HC

American Electric Power Company, Inc.
Liability Account Balances - Holding Company
Test Year Ending December 31, 2018
Docket No. 19-008-U

Account	Account Title	Actual Jul YTD 2018	Budget Aug YTD 2018	Budget Sep YTD 2018	Budget Oct YTD 2018	Budget Nov YTD 2018	Budget Dec YTD 2018	13-Months Average
2360801	Federal Income Tax - IRS Audit	-	-	-	-	-	-	550,824
2360901	Accum Defd FIT- IRS Audit	-	-	-	-	-	-	(1,652,473)
2370006	Interest Accrd-Sen Unsec Notes	7,232,335	10,380,251	13,346,918	16,313,584	8,894,924	11,073,486	9,376,830
2370048	Acrd Int.- FIT Reserve - LT	181,249	-	-	-	-	-	329,648
2420000	Misc Current & Accrued Liab	3,744,594	5,686,587	5,686,587	5,686,587	5,686,587	5,686,587	4,304,816
2420511	Control Cash Disburse Account	74	-	-	-	-	-	165,703
2420520	Accr Defer Compensation Ben	358,400	-	-	-	-	-	199,227
2420529	1St Chic-Sharehold Serv-Agent	73,000	-	-	-	-	-	44,923
2420551	Unclaimed Dividends	1,346,851	-	-	-	-	-	954,418
2420643	Accrued Audit Fees	163,668	-	-	-	-	-	113,662
2450017	Deriv-Hdg-Unreal Ls-FV-Int-L/T	27,226,313	27,226,313	27,226,313	27,226,313	27,226,313	27,226,313	21,804,996
2450517	Deriv-Hdg-Unreal Ls-FV-Int-Cur	738,112	738,112	738,112	738,112	738,112	738,112	397,445
2530000	Other Deferred Credits	5,654,697	-	-	-	-	-	4,048,846
2530175	Legal Contingencies	(102)	-	-	-	-	-	(16)
2823001	Acc Dfrd FIT FAS 109 Flow Thru	54,521	-	-	-	-	-	33,085
2830015	ADIT-Fed-Hdg-CF-Int Rate	476,215	-	-	-	-	-	302,041
2831001	Accum Deferred FIT - Other	(13,688)	-	-	-	-	-	(7,370)
2833001	Acc Dfd FIT FAS 109 Flow Thru	2,462,185	3,168,427	3,343,933	3,519,440	3,694,947	3,870,454	2,872,485
2834001	Acc Defd FIT - SFAS 109 Excess	13,688	-	-	-	-	-	8,423
236000216	State Income Taxes	-	-	-	-	-	-	-
236000217	State Income Taxes	(50,050)	-	-	-	-	-	(30,792)
236001214	State Franchise Taxes	(1,575)	-	-	-	-	-	(969)
236001216	State Franchise Taxes	-	-	-	-	-	-	-
236001217	State Franchise Taxes	(400)	-	-	-	-	-	(246)
		3,596,052,875	2,823,104,963	3,138,443,122	3,683,001,642	4,047,934,684	4,523,642,608	3,429,526,776

Recap Schedules
(A) Schedule D-6.1 HC

American Electric Power Company, Inc.
Interest Bearing Liabilities' Expense Information - Holding Company
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE D-6.3 HC

I. Liability Subaccounts

Line No.	Expense Account No.	Account Title	Description of Interest Rate Determination	January 2018	February 2018	March 2018	April 2018	May 2018	June 2018	July 2018	August 2018	September 2018	October 2018	November 2018	December 2018	Total Annual Cost	Annual Cost Rate
1	430	Interest Short-term Debt - Affil (Money Pool)	AEP Money	737,336	708,525	913,964	1,083,285	1,005,113	941,922	1,043,494	418,413	840,074	890,886	885,508	895,344	10,363,865	2.35%
2	431	Interest Short-term Debt - NonAffil	Various	1,594,292	1,789,240	3,820,061	3,988,607	3,657,560	3,555,930	3,797,544	3,151,689	2,742,415	3,912,496	3,823,243	3,642,038	39,475,116	2.67%
																-	
																-	
																-	
3		Total		2,331,628	2,497,765	4,734,025	5,071,892	4,662,673	4,497,853	4,841,038	3,570,103	3,582,489	4,803,382	4,708,751	4,537,382	49,838,980	

Supporting Schedules and Workpapers:

Schedule D-6.2 HC

Recap Schedules:

Southerwestern Electric Power Company
Index- E Work Papers
Test Year Ending December 31, 2018
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Workpaper	Description
Schedule E-1	Balance Sheet - Total Company
Schedule E-2	Income Statement - Total Company
Schedule E-3	Other Income and Deductions
Schedule E-4	Adjustments to Other Income and Deductions
Schedule E-5	Audited Financial Statements
Schedule E-6	Standard Journal Entries
Schedule E-9	Chart of Accounts
Schedule E-10	Organizational Charts
Schedule E-11.1	Per Books Billing Determinants and Revenues - Test Year
Schedule E-11.2	Billing Determinants - Pro Forma Year
Schedule E-13	Other Operating Statistics
Schedule E-14	Calculatioin of AFUDC
WP E-14	Calculation of AFUDC
Schedule E-17A	Trial Balance - Income Statement
Schedule E-17B	Trial Balance - Balance Sheet
Schedule E-17 Part II A	Plant In Service
Schedule E-17 Part II B	Accumulated Provision for Depreciation

Southerwestern Electric Power Company
Balance Sheet - Total Company
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE E-1

Explanation: Schedule showing the balance sheet by account for the end of the historical test year or the end of the historical portion of a partially projected test year. Any utility which is a wholly-owned subsidiary of another company should also provide the information required on this schedule for the parent corporation on a stand-alone basis.

Line No.	Account Number	Description	Historical Test Year(1) July 31, 2018 Amount (A)(a)	Account Number	Description		Historical Test Year July 31, 2018 Amount (A)(a)
		Current Assets			**Current Liabilities**		
1	131, 134, 135, 136	Cash and cash equivalents	10,590,499	234	Accounts Payable- affiliates		120,645,656
2	142, 144	Accounts receivable customers, net	34,192,996	231	Note payable		-
3	145	Advances to parent	-	233	Notes payable- affiliates		106,690,962
4	173	Accrued unbilled revenues	56,833,992	232	Accounts Payable- other		107,842,065
5	143	Accounts receivable-other net	21,124,902	235	Customer deposits		63,929,187
6	171, 172	Interest and dividends receivable	925,936	236	Taxes accrued		70,923,178
7	146	Accounts receivable- associated companies	39,028,017	237	Interest accrued		33,037,570
8	151, 152	Fuel inventories at LIFO cost	83,433,659	241	Tax collections payable		7,039,665
9	154, 158.1	Materials and supplies at average cost	68,975,585	242	Miscellaneous current and accrued liabilities		123,010,079
10	174	Miscellaneous current and accrued assets	-	243	Obligations Under Capital Leases		4,169,009
11	175	Curr. Unreal Gains - NonAffil	7,730,794	244	Curr. Unreal Losses - NonAffil		2,792,421
12	176	Derivative instruments assets - hedges	-		**Total Current Liabilities**		**640,079,794**
13	165	Prepayments and other	31,082,708				
14					**Long-Term Debt**		
15		**Total Current Assets**	**353,919,088**	257	Unamt Gain on Reacquired Debt		13,529
16				224	Other long-term debt		2,443,500,000
17				226	Unamortized discount on long-term debt		(4,994,847)
18	121, 122, 123.1, 124, 129	**Other Property and Investments, at Cost**	**74,061,280**		**Total Long-Term Debt**	(C)	**2,438,518,682**
19							
20		Property, Plant and Equipment					
21	101, 105, 106, 114, 116 (2)	In Service	9,034,909,599		**Deferred Credits and Other Liabilities**		
22	107 (E)	Construction work in progress	213,767,956	228.2	Accumulated provision for injuries and damages		87,519
23		Total property, plant and equipment	9,248,677,555	228.3	Accrued pension and benefit obligations		11,893,405
24	108, 111, 115	Less accumulated depreciation	(2,970,087,916)	281, 282, 283	Accumulated Deferred Income Tax, Liability	(C)	1,215,683,895
25		**Net Property, Plant and Equipment**	**6,278,589,639**	255	Accumulated Deferred Investment Tax Credit		5,076,627
				227	Obligations Under Cap LSE - Noncurr		22,986,593
26				230	Asset retirement obligations	(B)	113,929,033
27				229	Accumulated provision for rate refunds		43,403,375
28				252, 253	Other deferred credits		25,692,860
29		**Deferred Charges and Other Assets**		254	Other regulatory liabilities		737,810,542
30					**Total Deferred Credits and Other Liabilities**		**2,176,563,850**
31	182.3	Other Regulatory Assets	436,019,493				
32	184, 186	Clearing Accounts & Deferred Debits	63,164,425		**Stockholders' Equity**		
33	181	Unamortized debt expense	14,208,765	201, 438	Common stock issued		135,659,520
34	189	Unamortized Loss on Reacquired Debt	4,332,612	210, 211	Other paid-in capital		676,550,701
35	190	Accumulated Deferred Income Tax, Asset	304,612,479	216, 216.1, 439	Unappropriated Retained Earnings		1,467,751,697
36	183	Other Deferred Charges and Other Assets	1,668,269	219	Accumulated other comprehensive income		(4,548,195)
37					Total Stockholders' Equity	(C)	**2,275,413,723**
38		**Total Deferred Charges and Other Assets**	**824,006,042**				
39							
40	(1)	**Total Assets**	7,530,576,049	(1)	**Total Liabilities and Stockholders' Equity**		7,530,576,049
41	Notes				**Reconciliation to Schedule D-1.2**		
42	(1) Reflects balance sheet as of historical test year-end.				**Acct 190**		(304,612,479)
43	(2) Exclude Accts, 105, 114 and 116 to Recap to F-1.2(F)				**Acct 181/189**		(18,541,377)
44					**Acct 142**		144,670,792
45					**Schedule D-1.2**		**7,352,092,986**
46							

Supporting Schedules
(a) Schedule E-17B

Recap Schedules
(A) Schedule B-1, B-3
(B) Schedule C-9
(C) Schedule D-1.2
(E) Schedule B-8
(F) Schedule F-1.2

Southerwestern Electric Power Company **SCHEDULE E-2**
Income Statement - Total Company
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the income statement by subaccount for 12 months ending with the last month of the historical test year or the 6 months ending with the last historical month if using a projected test year

Line No.	Account Number	Description		Test Year Ending December 31, 2018 Amount (a)
1	440, 442, 444, 445, 447, 449.1, 450	Operating Revenues	(a)	1,831,204,179
2	451, 454, 456, 456.1			
3				
4		Operating Expenses:		
5	500, 501, 546, 547	Total Fuel		530,385,769
6	555	Purchased Power		180,176,090
7	*1	Operation		286,291,650
8	*2	Maintenance		147,375,175
	575.7	Regional Market		1,514,936
	901-905, 907-913, 916	Customer Service and Sales		39,811,393
9	401, 403, 403.1	Depreciation		221,460,017
10	404, 407	Amortization & Regulatory Debits		20,240,207
11	408.1	Taxes Other than Income Taxes		102,213,260
12	409.1	Federal Income Taxes		27,431,535
13	409.1	State Income Taxes		-
14	410.1	Deferred Income Taxes		777,092,760
15	411.1	Deferred Income Taxes-Credit		(783,738,049.89)
16	411.4	Investment Tax Credit, net		(1,244,396)
17	411.01	Accretion Expense		2,558,193
18	411.6, 411.8	Gain from Disposition of Allowances		619,127
19		Total Operating Expense		1,552,187,666
20				
21		Net Utility Operating Income		**279,016,514**
22				
23		Other Income & Deductions:	(b)	
24		Other Income:		
25	419	Interest & Dividend Income		4,830,346
26	415, 416, 417, 417.1, 418, 419.1, 421	Miscellaneous Income		7,938,918
27	421.1	Gain on Disposition of Property		3,199,999
28	418.1	Subsidiary Earnings		2,535,756
29		Total Other Income		18,505,019
30		Other Income Deductions:		
31		Expenditures for Certain Civic,		
32	426.4	Political & Related Activities		1,135,403
33	426.1	Donations		626,458
34	421.2, 425, 426.3, 426.5	Miscellaneous Income Deductions		37,198,477
35		Total Other Income Deductions		38,960,338
36				
37	408.2, 411.2, 410.2, 409.2	Income Taxes		(7,115,341)
38				
39		Net Other Income & Deductions		**265,676,537**
40				
41		Interest Charges:	(c)	
42	427, 428, 428.1, 429.1	Interest on Long-Term Debt		117,093,659
43	430, 431	Other Interest Expense		8,140,197
44	432	AFUDC		(6,222,225)
45		Total Interest Charges		**119,011,631**
46				
47		Net Income		146,664,906

Supporting Schedules and Workpapers:
(a) Schedule C-3
(b) Schedule E-3
(c) Schedule E-17A

*1 502, 505, 506, 507, 509, 546, 548, 556, 557, 560, 561, 562, 563, 565, 566, 567, 580, 581, 582, 583, 584, 585, 586, 587, 588, 589, 920, 921, 922, 923, 924, 925, 926, 927, 928, 929, 930.1, 930.2, 931

*2 510, 511, 512, 513, 514, 551, 552, 553, 554, 568, 569, 570, 571, 572, 573, 590, 591, 592, 593, 594, 595, 596, 597, 598, 935

Southerwestern Electric Power Company
Other Income and Deductions
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE E-3

Explanation: Schedule showing test year and pro forma other income and deductions, interest charges and extraordinary items. Amount reflected in the financial statements for for the historical portion of the test year. If the test year is entirely historical, column 1 shall show the amount reflected in the financial statements for the test year.

Line No.	Description	Account Number	(1) Actual Amount per Financial Statements for 7 months ending July 31. 2018 (c)	(2) Projected Activity For 5 Months Ending Dec. 31. 2018 (c)	(3) Total Test Year Dec. 31. 2018(a)	(4) Pro Forma Adjustments(b)	(5) Pro Forma Year
			Total Company				
1	Other Income:						
2	Interest & Dividend Income	419	2,591,319	2,239,027	4,830,346	(2,304,730)	2,525,616
3	Miscellaneous Income	415, 416, 417, 417.1, 418, 419.1, 421	3,703,746	4,235,172	7,938,918	1,698,360	9,637,278
4	Gain on Disposition of Property	421.1	-	3,199,999	3,199,999	(3,199,999)	-
5	Subsidiary Earnings	418.1	1,459,972	1,075,784	2,535,756	809,102	3,344,858
6	Total Other Income		7,755,037	10,749,982	18,505,019	(2,997,267)	15,507,752
7	Other Income Deductions:						
8	Exp. For Civic, Political & Related Activ.	426.4	638,614	496,789	1,135,403	(75,054)	1,060,349
9	Donations	426.1	307,513	318,945	626,458	161,343	787,801
10	Miscellaneous Income Deductions	421.2, 425, 426.3, 426.5	30,518,304	6,680,173	37,198,477	(27,330,369)	9,868,108
11	Total Other Income Deductions		31,464,431	7,495,907	38,960,338	(27,244,080)	11,716,258
12	Income Taxes	408.2,409.2, 410.2,411.2	(6,665,515)	(449,826)	(7,115,341)	4,928,795	(2,186,546)
13	Net Other Income & Deductions		**(17,043,878)**	**3,703,901**	**(13,339,977)**	**19,318,017**	**5,978,040**
14	Interest Charges	427, 428, 429, 430, 431, 432	69,338,843	49,672,788	119,011,631	(2,089,649)	116,921,982

Note: Interest includes forecasted amounts for pro-forma year. These amounts do not reflect adjustments to reflect the weighted cost of capital. No extraordinary items.

Supporting Schedules and Workpapers:
(a) Schedule E-2
(b) Schedule E-4
(c) Schedule E-17A

Recap Schedules

Southerwestern Electric Power Company
Adjustments to Other Income and Deductions
Test Year Ending December 31, 2018
Docket No. 19-008-U

Schedule E-4

Explanation: Schedule showing pro forma adjustments and reclassifications affecting test year other income and deductions.

(1) Line No.	(2) Account Description	(3) Account No.	(4) Adj. No.	(5) Adjustment Description	(6) Pro Forma Test Year Adjustment	(7) Pro Forma Test Year Reclass
	Other Income:					
1	Non-Operatng Rental Income	4180001		Not included in Cost of Service	(235)	
2	Equity Erngs of Sub-Consolidat	4181001		Not included in Cost of Service	(18,290)	
3	Equity Erngs of Sub-Nonconsol	4181002		Not included in Cost of Service	827,392	
4	Int & Dividend Inc - Nonassoc	4190002		Not included in Cost of Service	(817,903)	
5	Interest Income - Assoc CBP	4190005		Not included in Cost of Service	(1,486,827)	
6	Allw Oth Fnds Usd Drng Cnstr	4191000		Not included in Cost of Service	1,663,640	
7	Misc Non-Op Inc-NonAsc-Rents	4210002		Not included in Cost of Service	153	
8	Misc Non-Op Inc - NonAsc - Oth	4210007		Not included in Cost of Service	30,045	
9	Misc Non-Op Exp - NonAssoc	4210009		Not included in Cost of Service	4,756	
10	Gain on Dspsition of Property	4211000		Not included in Cost of Service	(3,199,999)	
					(2,997,267)	
	Other Income Deductions					
11	Donations	4261000		Not included in Cost of Service	161,343	
12	Penalties	4263001		Not included in Cost of Service	(72,696)	
13	Penalties - Quality of Service	4263003		Not included in Cost of Service	(114,189)	
14	Civic and Political Activity	4264000		Not included in Cost of Service	(33,373)	
15	Non-deduct Lobbying per IRS	4264001		Not included in Cost of Service	(41,681)	
16	Other Deductions - Nonassoc	4265002		Not included in Cost of Service	(586,042)	
17	Social & Service Club Dues	4265004		Not included in Cost of Service	(10,816)	
18	Shutdown Coal Company Exp	4265006		Not included in Cost of Service	(2,769,537)	
19	Regulatory Expenses	4265007		Not included in Cost of Service	(3,951)	
20	Factored Cust A/R Exp - Affil	4265009		Included in WCOC - WP D-1-1		592,793
21	Fact Cust A/R-Bad Debts-Affil	4265010	IS-13	Reclassified to Acct 904- WP C-2-13		407,079
22	Transition Costs	4265033		Not included in Cost of Service	(1,066)	
23	Wind Catcher Project Expenses	4265038		Not included in Cost of Service	(24,771,944)	
					(28,243,952)	999,872
	Income Taxes					
24	Inc Tax, Oth Inc&Ded-Federal	4092001		Not included in Cost of Service	4,927,767	
25	Inc Tax Oth Inc Ded - State	409200218		Not included in Cost of Service	946,238	
26	Prov Def I/T Oth I&D - Federal	4102001		Not included in Cost of Service	(2,024,667)	
27	Prv Def I/T-Cr Oth I&D-Fed	4112001		Not included in Cost of Service	1,079,457	
28					4,928,795	
29	NET NON OPERATING INCOME				20,317,890	(999,872)
30	**Interest**					
31	Int on LTD - Install Pur Contr	4270002			(1,581,738)	
32	Int on LTD - Other LTD	4270005			(2,135,990)	
33	Int on LTD - Sen Unsec Notes	4270006			3,990,506	
34	Amrtz Debt Dscnt&Exp-Instl Pur	4280002			(3,536)	
35	Amrtz Debt Dscnt&Exp-N/P	4280003			0	
36	Amrtz Dscnt&Exp-Sn Unsec Note	4280006			(47,753)	
37	Amrtz Loss Rcquired Debt-FMB	4281001			(83,720)	
38	Amrtz LossRcquired Debt-IPC	4281002			(48,624)	
39	Amrtz Loss Rcquired Debt-Dbnt	4281004			(95,632)	
40	Amrtz Gain Rcqred Debt-Cr-FMB	4291001			6,482	
41	Int to Assoc Co - CBP	4300003			(1,531,625)	
42	Other Interest Expense	4310001			(60,358)	
43	Interest on Customer Deposits	4310002			(35,178)	
44	Lines Of Credit	4310007			(687,701)	390,220
45	Other Interest - Fuel Recovery	4310014			40,000	
46	Mine Reclamation Interest	4310017			(72,503)	
47	Interest Expense - State Tax	4310023			(90,660)	
48	Allw Brrwed Fnds Used Cnstr-Cr	4320000			(41,838)	
49					(2,479,869)	390,220

Note: No extraordinary items.

Supporting Schedules:
(a) Schedule E-17A

Recap Schedules
(A) Schedule E-3

Southerwestern Electric Power Company **SCHEDULE E-5**
Audited Financial Statements
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: A copy of the most recent audited financial statement and/or the most recent annual report to the stockholders.

Line No.	Description
1	A copy of the most recent annual report to stockholders can also be found at https://www.aep.com/investors/financial See Also Attached

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to_________

Commission File Number	Registrants; States of Incorporation; Address and Telephone Number	I.R.S. Employer Identification Nos.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation)	13-4922640
333-221643	AEP TEXAS INC. (A Delaware Corporation)	51-0007707
333-217143	AEP TRANSMISSION COMPANY, LLC (A Delaware Limited Liability Company)	46-1125168
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation)	54-0124790
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation)	35-0410455
1-6543	OHIO POWER COMPANY (An Ohio Corporation)	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation)	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation) 1 Riverside Plaza, Columbus, Ohio 43215 Telephone (614) 716-1000	72-0323455

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of each class	Name of Each Exchange on Which Registered
American Electric Power Company, Inc.	Common Stock, $6.50 par value	New York Stock Exchange
AEP Texas Inc.	None	
AEP Transmission Company, LLC	None	
Appalachian Power Company	None	
Indiana Michigan Power Company	None	
Ohio Power Company	None	
Public Service Company of Oklahoma	None	
Southwestern Electric Power Company	None	

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant American Electric Power Company, Inc. is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.	Yes ☒	No ☐
Indicate by check mark if the registrants AEP Texas Inc., AEP Transmission Company, LLC, Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company, are well-known seasoned issuers, as defined in Rule 405 of the Securities Act.	Yes ☐	No ☒
Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.	Yes ☐	No ☒
Indicate by check mark whether the registrants American Electric Power Company, Inc., AEP Texas Inc., AEP Transmission Company, LLC, Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.	Yes ☒	No ☐
Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).	Yes ☒	No ☐
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (229.405 of this chapter) is not contained herein and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.	☒	

Indicate by check mark whether American Electric Power Company, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
Emerging growth company	☐		

Indicate by check mark whether AEP Texas Inc., AEP Transmission Company, LLC, Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company are large accelerated filers, accelerated filers, non-accelerated filers, smaller reporting companies, or emerging growth companies. See definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer	☒	Smaller reporting company	☐
Emerging growth company	☐		

If an emerging growth company, indicate by check mark if the registrants have elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark if the registrants are shell companies, as defined in Rule 12b-2 of the Exchange Act.	Yes ☐	No ☒

AEP Texas Inc., AEP Transmission Company, LLC, Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to such Form 10-K.

	Aggregate Market Value of Voting and Non-Voting Common Equity Held by Non-Affiliates of the Registrants as of June 30, 2018 the Last Trading Date of the Registrants' Most Recently Completed Second Fiscal Quarter	Number of Shares of Common Stock Outstanding of the Registrants as of December 31, 2018
American Electric Power Company, Inc.	$34,157,276,913	493,245,876
		($6.50 par value)
AEP Texas Inc.	None	100
		($0.01 par value)
AEP Transmission Company, LLC (a)	None	NA
Appalachian Power Company	None	13,499,500
		(no par value)
Indiana Michigan Power Company	None	1,400,000
		(no par value)
Ohio Power Company	None	27,952,473
		(no par value)
Public Service Company of Oklahoma	None	9,013,000
		($15 par value)
Southwestern Electric Power Company	None	7,536,640
		($18 par value)

(a) 100% interest is held by AEP Transmission Holdco.
NA Not applicable.

Note on Market Value of Common Equity Held by Non-Affiliates

American Electric Power Company, Inc. owns all of the common stock of AEP Texas Inc., Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company and all of the LLC membership interest in AEP Transmission Company, LLC (see Item 12 herein).

Documents Incorporated By Reference

Description	Part of Form 10-K into which Document is Incorporated
Portions of Annual Reports of the following companies for the fiscal year ended December 31, 2018:	Part II
American Electric Power Company, Inc.	
AEP Texas Inc.	
AEP Transmission Company, LLC	
Appalachian Power Company	
Indiana Michigan Power Company	
Ohio Power Company	
Public Service Company of Oklahoma	
Southwestern Electric Power Company	
Portions of Proxy Statement of American Electric Power Company, Inc. for 2019 Annual Meeting of Shareholders.	Part III

This combined Form 10-K is separately filed by American Electric Power Company, Inc., AEP Texas Inc., AEP Transmission Company, LLC, Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Except for American Electric Power Company, Inc., each registrant makes no representation as to information relating to the other registrants.

You can access financial and other information at AEP's website, including AEP's Principles of Business Conduct, certain committee charters and Principles of Corporate Governance. The address is www.AEP.com. Investors can obtain copies of our SEC filings from this site free of charge, as well as from the SEC website at www.sec.gov.

TABLE OF CONTENTS

GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority-owned consolidated subsidiaries and consolidated affiliates.
AEP Clean Energy Resources, LLC	A nonregulated holding company for AEP's competitive renewable generation and a wholly-owned subsidiary of AEP Energy Supply, LLC.
AEP Energy	AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States.
AEP Energy Supply, LLC	A nonregulated holding company for AEP's competitive generation, wholesale and retail businesses, and a wholly-owned subsidiary of AEP.
AEP OnSite Partners, LLC	A wholly-owned subsidiary of AEP Energy Supply, LLC.
AEP Renewables, LLC	A wholly-owned subsidiary of AEP Energy Supply, LLC.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEP Texas	AEP Texas Inc., an AEP electric utility subsidiary.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, hedging activities, asset management and commercial and industrial sales in the deregulated Ohio and Texas markets.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a wholly-owned subsidiary of AEP Transmission Holdco, is an intermediate holding company that owns the State Transcos.
AEPTCo Parent	AEP Transmission Company, LLC, the holding company of the State Transcos within the AEPTCo consolidation.
AEPTHCo	AEP Transmission Holding Company, LLC, a subsidiary of AEP, an intermediate holding company that owns transmission operations joint ventures and AEPTCo.
AFUDC	Allowance for Funds Used During Construction.
AGR	AEP Generation Resources Inc., a competitive AEP subsidiary in the Generation & Marketing segment.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
CAA	Clean Air Act.
CO_2	Carbon dioxide and other greenhouse gases.
Conesville Plant	A generation plant consisting of three coal-fired generating units totaling 1,695 MW located in Conesville, Ohio. The plant is jointly owned by AGR and a nonaffiliate.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,278 MW nuclear plant owned by I&M.
CSPCo	Columbus Southern Power Company, a former AEP electric utility subsidiary that was merged into OPCo effective December 31, 2011.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP Transmission Holdco and Berkshire Hathaway Energy Company formed to own and operate electric transmission facilities in ERCOT.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIP	Federal Implementation Plan.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.

IMTCo	AEP Indiana Michigan Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.

Term	Meaning
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
kV	Kilovolt.
MISO	Midwest Independent Transmission System Operator.
MMBtu	Million British Thermal Units.
MW	Megawatt.
MWh	Megawatt-hour.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NO_x	Nitrogen oxide.
NRC	Nuclear Regulatory Commission.
OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.
OHTCo	AEP Ohio Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
Oklaunion Power Station	A single unit coal-fired generation plant totaling 650 MW located in Vernon, Texas. The plant is jointly owned by AEP Texas, PSO and certain nonaffiliated entities.
OKTCo	AEP Oklahoma Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PPA	Purchase Power and Sale Agreement.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Racine	A generation plant consisting of two hydroelectric generating units totaling 47.5 MWs located in Racine, Ohio and owned by AGR.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants: AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.
Registrants	SEC registrants: AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.
REP	Texas Retail Electric Provider.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
ROE	Return on Equity.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SEC	U.S. Securities and Exchange Commission.
SIP	State Implementation Plan.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
State Transcos	AEPTCo's seven wholly-owned, FERC regulated, transmission only electric utilities, each of which is geographically aligned with AEP existing utility operating companies.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.

TA	Transmission Agreement, effective November 2010, among APCo, I&M, KGPCo, KPCo, OPCo and WPCo with AEPSC as agent.

Term	Meaning
TCA	Transmission Coordination Agreement dated January 1, 1997, by and among, PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two public utility subsidiaries.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
UPA	Unit Power Agreement.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.
WVTCo	AEP West Virginia Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.

FORWARD-LOOKING INFORMATION

This report made by the Registrants contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in "Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations," but there are others throughout this document which may be identified by words such as "expect," "anticipate," "intend," "plan," "believe," "will," "should," "could," "would," "project," "continue" and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document are presented as of the date of this document. Except to the extent required by applicable law, management undertakes no obligation to update or revise any forward-looking statement. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- Changes in economic conditions, electric market demand and demographic patterns in AEP service territories.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability or cost of capital to finance new capital projects and refinance existing debt.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load and customer growth.
- Weather conditions, including storms and drought conditions, and the ability to recover significant storm restoration costs.
- The cost of fuel and its transportation, the creditworthiness and performance of fuel suppliers and transporters and the cost of storing and disposing of used fuel, including coal ash and SNF.
- Availability of necessary generation capacity, the performance of generation plants and the availability of fuel.
- The ability to recover fuel and other energy costs through regulated or competitive electric rates.
- The ability to build or acquire renewable generation, transmission lines and facilities (including the ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs.
- New legislation, litigation and government regulation, including oversight of nuclear generation, energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances that could impact the continued operation, cost recovery and/or profitability of generation plants and related assets.
- Evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions, including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance.
- Resolution of litigation.
- The ability to constrain operation and maintenance costs.
- Prices and demand for power generated and sold at wholesale.
- Changes in technology, particularly with respect to energy storage and new, developing, alternative or distributed sources of generation.
- The ability to recover through rates any remaining unrecovered investment in generation units that may be retired before the end of their previously projected useful lives.
- Volatility and changes in markets for capacity and electricity, coal and other energy-related commodities, particularly changes in the price of natural gas.
- Changes in utility regulation and the allocation of costs within regional transmission organizations, including ERCOT, PJM and SPP.
- Changes in the creditworthiness of the counterparties with contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of debt.
- The impact of volatility in the capital markets on the value of the investments held by the pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact of such volatility on future funding requirements.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.

- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, naturally occurring and human-caused fires, cyber security threats and other catastrophic events.

The forward-looking statements of the Registrants speak only as of the date of this report or as of the date they are made. The Registrants expressly disclaim any obligation to update any forward-looking information, except as required by law. For a more detailed discussion of these factors, see "Risk Factors" in Part I of this report.

Investors should note that the Registrants announce material financial information in SEC filings, press releases and public conference calls. Based on guidance from the SEC, the Registrants may use the Investors section of AEP's website (www.aep.com) to communicate with investors about the Registrants. It is possible that the financial and other information posted there could be deemed to be material information. The information on AEP's website is not part of this report.

PART I

ITEM 1. BUSINESS

GENERAL

Overview and Description of Major Subsidiaries

AEP was incorporated under the laws of the State of New York in 1906 and reorganized in 1925. It is a public utility holding company that owns, directly or indirectly, all of the outstanding common stock of its public utility subsidiaries and varying percentages of other subsidiaries.

The service areas of AEP's public utility subsidiaries cover portions of the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. Transmission networks are interconnected with extensive distribution facilities in the territories served. The public utility subsidiaries of AEP have traditionally provided electric service, consisting of generation, transmission and distribution, on an integrated basis to their retail customers. Restructuring laws in Michigan, Ohio and the ERCOT area of Texas have caused AEP public utility subsidiaries in those states to unbundle previously integrated regulated rates for their retail customers.

The member companies of the AEP System have contractual, financial and other business relationships with the other member companies, such as participation in the AEP System savings and retirement plans and tax returns, sales of electricity and transportation and handling of fuel. The companies of the AEP System also obtain certain accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost from a common provider, AEPSC.

As of December 31, 2018, the subsidiaries of AEP had a total of 17,582 employees. Because it is a holding company rather than an operating company, AEP has no employees. The material subsidiaries of AEP are as follows:

AEP Texas

Organized in Delaware in 1925, AEP Texas is engaged in the transmission and distribution of electric power to approximately 1,050,000 retail customers through REPs in west, central and southern Texas. As of December 31, 2018, AEP Texas had 1,549 employees. Among the principal industries served by AEP Texas are petroleum and coal products manufacturing, chemical manufacturing, oil and gas extraction, pipeline transportation and primary metal manufacturing. The territory served by AEP Texas also includes several military installations and correctional facilities. AEP Texas is a member of ERCOT. AEP Texas is part of AEP's Transmission and Distribution Utilities segment.

AEPTCo

Organized in Delaware in 2006, AEPTCo is a holding company for the State Transcos. The State Transcos develop and own new transmission assets that are physically connected to the AEP System. Individual State Transcos (a) have obtained the approvals necessary to operate in Indiana, Kentucky, Michigan, Ohio, Oklahoma and West Virginia, subject to any applicable siting requirements, (b) are authorized to submit projects for commission approval in Virginia and (c) have been granted consent to enter into a joint license agreement that will support investment in Tennessee. Neither AEPTCo nor its subsidiaries have any employees. Instead, AEPSC and certain AEP utility subsidiaries provide the services required by these entities. AEPTCo is part of the AEP Transmission Holdco segment.

APCo

Organized in Virginia in 1926, APCo is engaged in the generation, transmission and distribution of electric power to approximately 956,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. APCo owns 6,629 MWs of generating capacity. APCo uses its generation to serve its retail and other customers. As of December 31, 2018, APCo had 1,797 employees. Among the principal industries served by APCo are coal mining, primary metals, pipeline transportation, chemical manufacturing and paper manufacturing. APCo is a member of PJM. APCo is part of AEP's Vertically Integrated Utilities segment.

I&M

Organized in Indiana in 1907, I&M is engaged in the generation, transmission and distribution of electric power to approximately 596,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. I&M owns or leases 3,624 MWs of generating capacity, which it uses to serve its retail and other customers. As of December 31, 2018, I&M had 2,400 employees. Among the principal industries served are primary metals, transportation equipment, chemical manufacturing, plastics and rubber products and fabricated metal product manufacturing. I&M is a member of PJM. I&M is part of AEP's Vertically Integrated Utilities segment.

KPCo

Organized in Kentucky in 1919, KPCo is engaged in the generation, transmission and distribution of electric power to approximately 166,000 retail customers in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. KPCo owns 1,060 MWs of generating capacity. KPCo uses its generation to serve its retail and other customers. As of December 31, 2018, KPCo had 522 employees. Among the principal industries served are petroleum and coal products manufacturing, chemical manufacturing, coal mining, oil and gas extraction and primary metals. KPCo is a member of PJM. KPCo is part of AEP's Vertically Integrated Utilities segment.

KGPCo

Organized in Virginia in 1917, KGPCo provides electric service to approximately 48,000 retail customers in Kingsport and eight neighboring communities in northeastern Tennessee. KGPCo does not own any generating facilities and is a member of PJM. It purchases electric power from APCo for distribution to its customers. As of December 31, 2018, KGPCo had 55 employees. KGPCo is part of AEP's Vertically Integrated Utilities segment.

OPCo

Organized in Ohio in 1907 and re-incorporated in 1924, OPCo is engaged in the transmission and distribution of electric power to approximately 1,486,000 retail customers in Ohio. OPCo purchases energy and capacity at auction to serve generation service customers who have not switched to a competitive generation supplier. As of December 31, 2018, OPCo had 1,704 employees. Among the principal industries served by OPCo are primary metals, petroleum and coal products manufacturing, plastics and rubber products, chemical manufacturing, fabricated metal product manufacturing and data centers. OPCo is a member of PJM. OPCo is part of AEP's Transmission and Distribution Utilities segment.

PSO

Organized in Oklahoma in 1913, PSO is engaged in the generation, transmission and distribution of electric power to approximately 556,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. PSO owns 3,893 MWs of generating capacity, which it uses to serve its retail and other customers. As of December 31, 2018, PSO had 1,125 employees. Among the principal industries served by PSO are paper manufacturing, oil and gas extraction, petroleum and coal products manufacturing, transportation equipment and pipeline transportation. PSO is a member of SPP. PSO is part of AEP's Vertically Integrated Utilities segment.

SWEPCo

Organized in Delaware in 1912, SWEPCo is engaged in the generation, transmission and distribution of electric power to approximately 537,000 retail customers in northeastern and panhandle of Texas, northwestern Louisiana and western Arkansas and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. SWEPCo owns 5,240 MWs of generating capacity, which it uses to serve its retail and other customers. As of December 31, 2018, SWEPCo had 1,469 employees. Among the principal industries served by SWEPCo are petroleum and coal products manufacturing, food manufacturing, paper manufacturing, oil and gas extraction and chemical manufacturing. The territory served by SWEPCo includes several military installations, colleges and universities. SWEPCo also owns and operates a lignite coal mining operation. SWEPCo is a member of SPP. SWEPCo is part of AEP's Vertically Integrated Utilities segment.

WPCo

Organized in West Virginia in 1883 and reincorporated in 1911, WPCo provides electric service to approximately 42,000 retail customers in northern West Virginia. WPCo owns 780 MWs of generating capacity which it uses to serve its retail and other customers. WPCo is a member of PJM. As of December 31, 2018, WPCo had 57 employees. WPCo is part of AEP's Vertically Integrated Utilities segment.

Service Company Subsidiary

AEPSC is a service company subsidiary that provides accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost to AEP subsidiaries. The executive officers of AEP and certain of its public utility subsidiaries are employees of AEPSC. As of December 31, 2018, AEPSC had 6,335 employees.

Company Website and Availability of SEC Filings

Our principal corporate website address is www.aep.com. Information on our website is not incorporated by reference herein and is not part of this Form 10-K. We make available free of charge through our website our Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after such documents are electronically filed with, or furnished to, the SEC. The SEC maintains a website at www.sec.gov that contains reports, proxy and information statements and other information regarding AEP.

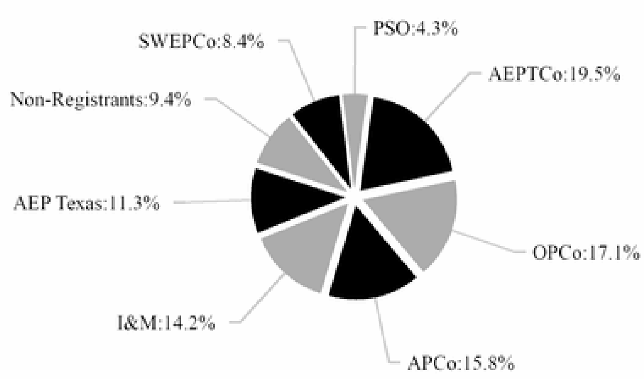
Public Utility Subsidiaries by Jurisdiction

The following table illustrates certain regulatory information with respect to the jurisdictions in which the public utility subsidiaries of AEP operate:

Principal Jurisdiction	AEP Utility Subsidiaries Operating in that Jurisdiction	Authorized Return on Equity (a)	
FERC	AEPTCo - PJM	10.99%	(b)
	AEPTCo - SPP	10.70%	(c)
Ohio	OPCo	10.20%	(d)
West Virginia	APCo	9.75%	
	WPCo	9.75%	
Virginia	APCo	9.70%	
Indiana	I&M	9.95%	
Michigan	I&M	9.90%	
Texas	AEP Texas	9.96%	
	SWEPCo	9.60%	
Tennessee	KGPCo	9.85%	
Kentucky	KPCo	9.70%	
Louisiana	SWEPCo	9.80%	
Arkansas	SWEPCo	10.25%	
Oklahoma	PSO	9.30%	

(a) Identifies the predominant authorized ROE and may not include other, less significant, permitted recovery. Actual ROE varies from authorized ROE.
(b) Current authorized ROE is 10.99%. In March 2018, a settlement agreement was filed at FERC lowering the ROE to 9.85% (10.35% inclusive of the RTO incentive adder of 0.5%). See "FERC Transmission Complaint - AEP's PJM Participants" section of Note 4 included in the 2018 Annual Report.
(c) Current authorized ROE is being challenged. See "FERC Transmission Complaint - AEP's SPP Participants" section of Note 4 included in the 2018 Annual Report.
(d) Authorized ROE was approved in OPCo's last distribution base case. The authorized ROE for riders with an approved equity return (e.g. Distribution Investment Rider) is 10.00%. See "Ohio Electric Security Plan Filings" section of Note 4 included in the 2018 Annual Report.

Percentage of AEP Consolidated Pretax Income by Registrant Subsidiary (a)
for the year ended December 31, 2018



(a) Pretax income does not include intercompany eliminations.

CLASSES OF SERVICE

The principal classes of service from which the public utility subsidiaries of AEP derive revenues and the amount of such revenues during the years ended December 31, 2018, 2017 and 2016 are as follows:

	Years Ended December 31,		
Description	**2018**	**2017**	**2016**
		(in millions)	
Vertically Integrated Utilities Segment			
Retail Revenues			
Residential Sales	$ 3,818.5	$ 3,399.8	$ 3,423.1
Commercial Sales	2,251.4	2,148.6	2,102.2
Industrial Sales	2,234.1	2,156.9	2,050.6
PJM Net Charges	0.4	(1.1)	(0.4)
Other Retail Sales	186.4	181.4	172.9
Total Retail Revenues	8,490.8	7,885.6	7,748.4
Wholesale Revenues			
Off-system Sales	888.0	907.4	921.5
Transmission	263.7	202.2	198.2
Total Wholesale Revenues	1,151.7	1,109.6	1,119.7
Other Electric Revenues	93.7	106.1	114.5
Provision for Rate Refund	(210.1)	(46.4)	(10.0)
Other Operating Revenues	30.6	40.2	39.9
Sales to Affiliates	88.8	96.9	79.4
Total Revenues Vertically Integrated Utilities Segment	$ 9,645.5	$ 9,192.0	$ 9,091.9
Transmission and Distribution Utilities Segment			
Retail Revenues			
Residential Sales	$ 2,213.5	$ 2,085.3	$ 2,217.9
Commercial Sales	1,288.3	1,225.3	1,210.0
Industrial Sales	499.2	473.0	498.2
Other Retail Sales	39.6	39.8	38.9
Total Retail Revenues	4,040.6	3,823.4	3,965.0
Wholesale Revenues			
Off-system Sales	119.3	100.5	131.0
Transmission	394.7	359.6	327.0
Total Wholesale Revenues	514.0	460.1	458.0
Other Electric Revenues	54.5	48.4	55.6
Provision for Rate Refund	(69.2)	(11.4)	(159.3)
Other Operating Revenues	12.4	8.4	8.9
Sales to Affiliates	100.8	90.4	94.2
Total Revenues Transmission and Distribution Utilities Segment	$ 4,653.1	$ 4,419.3	$ 4,422.4
AEP Transmission Holdco Segment			
Transmission Revenues	$ 291.3	$ 204.3	$ 150.6
Other Electric Revenues	0.3	—	—
Other Operating Revenues	0.3	0.8	0.1
Sales to Affiliates	555.5	588.3	366.9
Provision for Rate Refund	(43.3)	(26.7)	(4.8)
Total Revenues AEP Transmission Holdco Segment	$ 804.1	$ 766.7	$ 512.8
Generation & Marketing Segment			
Generation Revenues			
Affiliated	$ —	$ —	$ 0.1
Nonaffiliated	431.5	534.6	1,534.0
Marketing, Competitive Retail and Renewable Revenues			
Affiliated	122.2	103.7	127.2
Nonaffiliated	1,386.6	1,236.8	1,324.7

Total Revenues Generation & Marketing Segment	$ 1,940.3	$ 1,875.1	$ 2,986.0

AEP Texas

Description	Years Ended December 31, 2018	2017	2016
	(in millions)		
Retail Revenues			
Residential Sales	$ 594.6	$ 573.9	$ 551.2
Commercial Sales	448.1	449.3	421.2
Industrial Sales	113.0	107.0	102.9
Other Retail Sales	26.6	26.6	24.8
Total Retail Revenues	1,182.3	1,156.8	1,100.1
Wholesale Revenues			
Transmission	313.4	293.8	258.0
Other Electric Revenues	21.9	20.8	25.1
Provision for Rate Refund	(31.3)	(1.1)	—
Total Electric Transmission and Distribution Revenues	1,486.3	1,470.3	1,383.2
Sales to Affiliates	105.2	65.7	75.7
Other Revenues	3.8	2.4	2.5
Total Revenues	$ 1,595.3	$ 1,538.4	$ 1,461.4

AEPTCo

Description	Years Ended December 31, 2018	2017	2016
	(in millions)		
Transmission Revenues	$ 212.8	$ 167.9	$ 114.3
Other Electric Revenues	0.3	—	—
Other Operating Revenues	0.2	0.8	0.1
Sales to Affiliates	598.9	580.5	367.5
Provision for Rate Refund	(36.1)	(26.0)	(3.9)
Total Revenues	$ 776.1	$ 723.2	$ 478.0

APCo

Description	Years Ended December 31, 2018	2017	2016
	(in millions)		
Retail Revenues			
Residential Sales	$ 1,372.0	$ 1,242.8	$ 1,314.8
Commercial Sales	598.3	586.0	603.0
Industrial Sales	618.8	639.0	628.9
PJM Net Charges	(0.2)	(0.4)	(0.6)
Other Retail Sales	79.5	78.0	80.5
Total Retail Revenues	2,668.4	2,545.4	2,626.6
Wholesale Revenues			
Off-system Sales	116.4	126.8	137.8
Transmission	56.3	57.1	45.9
Total Wholesale Revenues	172.7	183.9	183.7
Other Electric Revenues	31.1	33.4	40.5
Provision for Rate Refund	(95.1)	(13.7)	(3.4)
Total Electric Generation, Transmission and Distribution Revenues	2,777.1	2,749.0	2,847.4
Sales to Affiliates	181.4	172.0	142.1
Other Revenues	9.0	13.2	11.7
Total Revenues	$ 2,967.5	$ 2,934.2	$ 3,001.2

I&M

Description	2018	2017	2016
	Years Ended December 31, (in millions)		
Retail Revenues			
Residential Sales	$ 736.5	$ 620.9	$ 620.4
Commercial Sales	494.6	442.7	440.1
Industrial Sales	565.3	518.1	510.0
PJM Net Charges	0.2	(1.0)	0.1
Other Retail Sales	7.2	7.1	7.1
Total Retail Revenues	1,803.8	1,587.8	1,577.7
Wholesale Revenues			
Off-system Sales	459.3	431.2	446.6
Transmission	18.4	17.2	23.9
Total Wholesale Revenues	477.7	448.4	470.5
Other Electric Revenues	15.7	13.5	15.2
Provision for Rate Refund	(24.6)	(7.2)	(1.1)
Total Electric Generation, Transmission and Distribution Revenues	2,272.6	2,042.5	2,062.3
Sales to Affiliates	85.5	64.4	88.3
Other Revenues	12.6	14.3	17.0
Total Revenues	$ 2,370.7	$ 2,121.2	$ 2,167.6

OPCo

Description	2018	2017	2016
	Years Ended December 31, (in millions)		
Retail Revenues			
Residential Sales	$ 1,618.9	$ 1,511.3	$ 1,665.0
Commercial Sales	840.2	776.1	785.0
Industrial Sales	386.2	365.9	395.0
Other Retail Sales	13.0	13.2	14.0
Total Retail Revenues	2,858.3	2,666.5	2,859.0
Wholesale Revenues			
Off-system Sales	119.3	100.5	131.0
Transmission	61.4	65.8	68.9
Total Wholesale Revenues	180.7	166.3	199.9
Other Electric Revenues	32.7	31.0	30.5
Provision for Rate Refund	(37.9)	(10.3)	(159.3)
Total Electricity, Transmission and Distribution Revenues	3,033.8	2,853.5	2,930.1
Sales to Affiliates	21.0	24.4	17.3
Other Revenues	8.6	6.0	6.5
Total Revenues	$ 3,063.4	$ 2,883.9	$ 2,953.9

PSO

Description	2018	2017	2016
	Years Ended December 31, (in millions)		
Retail Revenues			
Residential Sales	$ 668.5	$ 601.4	$ 538.0
Commercial Sales	411.3	398.5	348.6
Industrial Sales	298.6	273.4	220.6
Other Retail Sales	84.2	80.9	70.8
Total Retail Revenues	1,462.6	1,354.2	1,178.0
Wholesale Revenues			
Off-system Sales	36.3	13.9	13.1
Transmission	47.4	42.3	38.3

Total Wholesale Revenues	83.7	56.2	51.4
Other Electric Revenues	10.3	8.5	14.9
Provision for Rate Refund	(19.0)	(1.4)	(0.1)
Total Electric Generation, Transmission and Distribution Revenues	1,537.6	1,417.5	1,244.2
Sales to Affiliates	5.4	4.3	3.1
Other Revenues	4.3	5.4	4.4
Total Revenues	$ 1,547.3	$ 1,427.2	$ 1,251.7

SWEPCo

Description	2018	2017	2016
	Years Ended December 31, (in millions)		
Retail Revenues			
Residential Sales	$ 665.9	$ 597.0	$ 587.7
Commercial Sales	510.6	492.5	479.0
Industrial Sales	338.3	331.4	307.1
Other Retail Sales	8.9	8.8	8.1
Total Retail Revenues	1,523.7	1,429.7	1,381.9
Wholesale Revenues			
Off-system Sales	216.8	251.3	243.9
Transmission	94.2	71.7	78.4
Total Wholesale Revenues	311.0	323.0	322.3
Other Electric Revenues	20.9	20.4	20.0
Provision for Rate Refund	(63.7)	(21.0)	(4.4)
Total Electric Generation, Transmission and Distribution Revenues	1,791.9	1,752.1	1,719.8
Sales to Affiliates	28.4	25.9	24.5
Other Revenues	1.6	1.9	2.0
Total Revenues	$ 1,821.9	$ 1,779.9	$ 1,746.3

FINANCING

General

Companies within the AEP System generally use short-term debt to finance working capital needs. Short-term debt may also be used to finance acquisitions, construction and redemption or repurchase of outstanding securities until such needs can be financed with long-term debt. In recent history, short-term funding needs have been provided for by cash on hand and AEP's commercial paper program. Funds are made available to subsidiaries under the AEP corporate borrowing program. Certain public utility subsidiaries of AEP also sell accounts receivable to provide liquidity. See "Financial Condition" section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in the 2018 Annual Report for additional information.

AEP's revolving credit agreement (which backstops the commercial paper program) includes covenants and events of default typical for this type of facility, including a maximum debt/capital test. In addition, the acceleration of AEP's payment obligations, or the obligations of certain of its major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under the credit agreement. As of December 31, 2018, AEP was in compliance with its debt covenants. With the exception of a voluntary bankruptcy or insolvency, any event of default has either or both a cure period or notice requirement before termination of the agreement. A voluntary bankruptcy or insolvency of AEP or one of its significant subsidiaries would be considered an immediate termination event. See "Financial Condition" section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in the 2018 Annual Report for additional information.

AEP's subsidiaries have also utilized, and expect to continue to utilize, additional financing arrangements, such as securitization financings and leasing arrangements, including the leasing of coal transportation equipment and facilities.

ENVIRONMENTAL AND OTHER MATTERS

General

AEP subsidiaries are currently subject to regulation by federal, state and local authorities with regard to air and water-quality control and other environmental matters, and are subject to zoning and other regulation by local authorities. The environmental issues that management believes are potentially material to the AEP System are outlined below.

Clean Water Act Requirements

Operations for AEP subsidiaries are subject to the Federal Clean Water Act, which prohibits the discharge of pollutants into waters of the United States except pursuant to appropriate permits and regulates systems that withdraw surface water for use in power plants. In 2014, the Federal EPA issued a final rule setting forth standards for existing power plants that is intended to reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. The standards affect all plants withdrawing more than two million gallons of cooling water per day. Compliance with this standard is required within eight years of the effective date of the final rule.

In November 2015, the Federal EPA issued a final rule revising effluent limitation guidelines for electricity generating facilities. The rule establishes limits on Flue Gas Desulfurization wastewater, fly ash and bottom ash transport water and flue gas mercury control wastewater to be imposed as soon as possible after November 2018 and no later than December 2023. See "Environmental Issues - Clean Water Act Regulations" section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in the 2018 Annual Report for additional information.

Coal Ash Regulation

AEP's operations produce a number of different coal combustion by-products, including fly ash, bottom ash, gypsum and other materials. The Federal EPA rule regulates the disposal and beneficial re-use of coal combustion residuals, including fly ash and bottom ash generated at coal-fired electric generating units. The rule requires certain standards for location, groundwater monitoring and dam stability to be met at landfills and certain surface impoundments at operating facilities. If existing disposal facilities cannot meet these standards, they will be required to close. See "Environmental Issues - Coal Combustion Residual Rule" section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in the 2018 Annual Report for additional information.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control mobile and stationary sources of air emissions. The major CAA programs affecting AEP's power plants are described below. The states implement and administer many of these programs and could impose additional or more stringent requirements.

The Acid Rain Program

The CAA includes a cap-and-trade emission reduction program for SO_2 emissions from power plants and requirements for power plants and requirements for power plants to reduce NO_x emissions through the use of available combustion controls, collectively called the Acid Rain Program. AEP continues to meet its obligations under the Acid Rain Program through the installation of controls, use of alternate fuels and participation in the emissions allowance markets.

National Ambient Air Quality Standards (NAAQS)

The CAA requires the Federal EPA to review the available scientific data for criteria pollutants periodically and establish a concentration level in the ambient air for those substances that is adequate to protect the public health and welfare with an extra safety margin. The Federal EPA also can list additional pollutants and develop concentration levels for them. These concentration levels are known as NAAQS.

Each state identifies the areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (non-attainment areas). Each state must develop a SIP to bring non-attainment areas into compliance with the NAAQS and maintain good air quality in attainment areas. All SIPs are submitted to the Federal EPA for approval. If a state fails to develop adequate plans, the Federal EPA develops and implements a plan. As the Federal EPA reviews the NAAQS and establishes new concentration levels, the attainment status of areas can change and states may be required to develop new SIPs. See "Environmental Issues - Clean Air Act Requirements" section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in the 2018 Annual Report for additional information.

Hazardous Air Pollutants (HAP)

The CAA also requires the Federal EPA to investigate HAP emissions from the electric utility sector and submit a report to Congress to determine whether those emissions should be regulated. In 2011, the Federal EPA issued a rule setting Maximum Achievable Control Technology standards for new and existing coal and oil-fired utility units and New Source Performance Standards for emissions from new and modified power plants. In 2014, the U.S. Supreme Court determined that the Federal EPA acted unreasonably in refusing to consider costs in determining if it was appropriate and necessary to regulate HAP emissions from electric generating units. The Federal EPA has engaged in additional rulemaking activity but the 2011 rule remains in effect. See "Environmental Issues - Hazardous Air Pollutants" section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in the 2018 Annual Report for additional information.

Regional Haze

The CAA establishes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing impairment of visibility in these areas Regional Haze program. In 2005, the Federal EPA issued its Clean Air Visibility Rule, detailing how the CAA's best available retrofit technology requirements will be applied to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants.

PSO executed a settlement with the Federal EPA and the State of Oklahoma to comply with Regional Haze program requirements in Oklahoma, and the settlement is now codified in the Oklahoma SIP and approved by the Federal EPA. The Federal EPA disapproved portions of the Arkansas and Texas SIPs, and finalized FIPs for both states. Challenges to both federal plans are pending in the courts. See "Environmental Issues - Clean Air Act Requirements" section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in the 2018 Annual Report for additional information.

Climate Change

AEP has taken action to reduce and offset CO_2 emissions from its generating fleet and expects CO_2 emissions from its operations to continue to decline due to the retirement of some of its coal-fired generation units, and actions taken to diversify the generation fleet and increase energy efficiency where there is regulatory support for such activities. In 2018, AEP announced new intermediate and long-term CO_2 emission reduction goals, based on the output of the company's integrated resource plans, which take into account economics, customer demand, regulations, grid reliability and resiliency, and reflect the company's current business strategy. The intermediate goal is a 60% reduction from 2000 CO_2 emission levels from AEP generating facilities by 2030; the long-term goal is an 80% reduction of CO_2 emissions from AEP generating facilities from 2000 levels by 2050. AEP's total estimated CO_2 emissions in 2018 were approximately 69 million metric tons, a 59% reduction from AEP's 2000 CO_2 emissions of approximately 167 million metric tons.

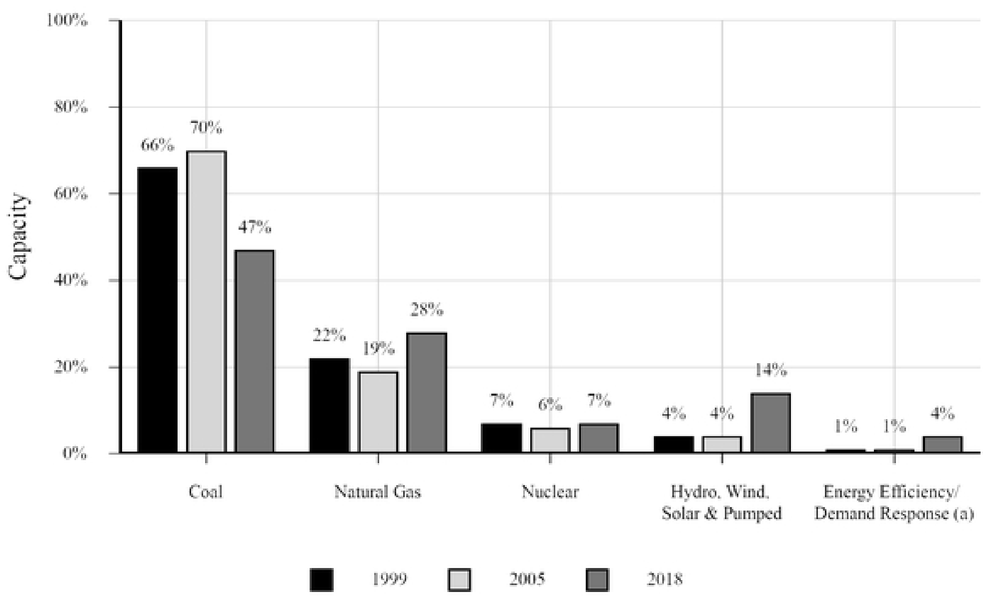
The Federal EPA has taken action to regulate CO_2 emissions from new and existing fossil fueled electric generating units under the existing provisions of the CAA. The Clean Power Plan was adopted in October 2015 but the U.S. Supreme Court issued a stay of its implementation, including all of the deadlines for submission of initial or final state plans. In 2017, the Federal EPA issued a proposal to repeal the Clean Power Plan and in 2018 the Federal EPA issued a proposal to revise the standards for new and modified sources and less stringent proposed guidelines to replace the Clean Power Plan. See "Environmental Issues - Climate Change, CO_2 Regulation and Energy Policy" section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in the 2018 Annual Report for additional information.

Management expects emissions to continue to decline over time as AEP diversifies generating sources and operates fewer coal units. The projected decline in coal-fired generation is due to a number of factors, including the ongoing cost of operating older units, the relative cost of coal and natural gas as fuel sources, increasing environmental regulations requiring significant capital investments and changing commodity market fundamentals. Management's strategy for this transformation includes diversifying AEP's fuel portfolio and generating more electricity from natural gas, increasing energy efficiency and investing in renewable resources, where there is regulatory support.

Transforming our Generation Fleet

The electric utility industry is in the midst of an historic transformation, driven by changing customer needs, policy demands, demographics, competitive offerings, technologies and commodity prices. Amid this changing landscape, AEP is also transforming to be more agile and customer-focused as a valued provider of energy solutions. AEP's long-term commitment to reduce CO2 emissions reflects the current direction of the company's resource plans to meet those needs. AEP's exposure to carbon regulation has been greatly reduced over the last several years. From 2000 to 2017, AEP's CO2 emissions declined 57 percent. In 2018, coal represented 47 percent of AEP's generating capacity, compared with 70 percent in 2005. Management expects the percentage of AEP's generating resources fueled by coal will continue to decline. Transforming AEP's generation portfolio to include more renewable energy and focusing on the efficient use of energy, demand response, distributed resources and technology solutions to more efficiently manage the grid over time is part of this strategy.

The graph below summarizes AEP's generation capacity by resource type for the years 1999, 2005 and 2018:



(a) Energy Efficiency/Demand Response represents avoided capacity rather than physical assets.

Renewable Sources of Energy

The states AEP serves, other than Kentucky, West Virginia and Tennessee, have established mandatory or voluntary programs to increase the use of energy efficiency, alternative energy or renewable energy sources.

As of December 31, 2018, AEP's regulated utilities had long-term contracts for 2,750 MWs of wind and 10 MWs of solar power delivering renewable energy to the companies' customers. In addition, I&M owns four solar projects that make up I&M's 15 MW Clean Energy Solar Pilot Project. Management actively manages AEP's compliance position and is on pace to meet the relevant requirements or benchmarks in each applicable jurisdiction.

The growth of AEP's renewable portfolio reflects the company's strategy to diversify its generation resources to provide clean energy options to customers. In addition to gradually reducing AEP's reliance on coal-fueled generating units, the growth of renewables and natural gas helps AEP to maintain a diversity of generation resources.

The integrated resource plans filed with state regulatory commissions by AEP's regulated utility subsidiaries reflect AEP's renewable strategy to balance reliability and cost with customers' desire for clean energy in a carbon-constrained world. AEP has committed significant capital investments to modernize the electric grid and integrate these new resources. Transmission assets of the AEP System interconnect approximately 11,900 MWs of renewable energy resources. AEP's transmission development initiatives are designed to facilitate the interconnection of additional renewable energy resources.

AEP Energy Supply, LLC owned 261 MWs of wind capacity in Texas as of December 31, 2018. AEP Renewables, LLC develops and/or acquires large scale renewable projects backed with long-term contracts with creditworthy counterparties. As of December 2018, AEP Renewables, LLC owned two 20 MW solar projects in California and Utah and a 50 MW solar project in Nevada. In December 2018, AEP Renewables, LLC entered into an agreement to own an additional 227 MWs of Texas wind capacity which is expected to be placed in-service in mid-2019.

AEP OnSite Partners, LLC works directly with wholesale and large retail customers to provide tailored solutions to reduce their energy costs based upon market knowledge, innovative applications of technology and deal structuring capabilities. The company targets opportunities in distributed solar, combined heat and power, energy storage, waste heat recovery, energy efficiency, peaking generation and other energy solutions that create value for customers. AEP OnSite Partners, LLC pursues and develops behind the meter projects with creditworthy customers. As of December 31, 2018, AEP OnSite Partners, LLC owned projects operating in 15 states, including approximately 85 MWs of installed solar capacity, and approximately 57 MWs of solar projects under construction.

In February 2019, AEP Clean Energy Resources, LLC signed an agreement to purchase Sempra Renewables, LLC and its 724 MWs of wind generation and battery assets for approximately $1.1 billion, subject to closing and working capital adjustments. As part of the purchase price, AEP Clean Energy Resources, LLC will pay $551 million in cash and assume $343 million of existing project debt obligations of the non-consolidated joint ventures. Additionally, the acquisition will be accompanied by the recognition of non-controlling tax equity interest of $162 million associated with certain of the acquired wind farms. The wind generation portfolio includes seven wholly or jointly-owned wind farms with long-term PPAs for 100% of their energy production. The transaction is expected to close in mid-2019 and is subject to regulatory approvals from the FERC and federal clearance pursuant to the Hart-Scott-Rodino Antitrust Improvements Act of 1976.

Competitive Renewable Generation Facilities

Size of Energy Resource	AEP Entity	Renewable Energy Resource	Location	In-Service or Under Construction
261 MW	AEP Energy Supply LLC	Wind	Texas	In-service
20 MW	AEP Renewables, LLC	Solar	California	In-service
20 MW	AEP Renewables, LLC	Solar	Utah	In-service
50 MW	AEP Renewables, LLC	Solar	Nevada	In-service
85 MW	AEP OnSite Partners, LLC	Solar	Fifteen states (a)	In-service
57 MW	AEP OnSite Partners, LLC	Solar	Four states (b)	Under Construction

(a) California, Colorado, Connecticut, Florida, Hawaii, Minnesota, Nebraska, New Hampshire, New Jersey, New Mexico, New York, Ohio, Rhode Island, Texas and Vermont.

(b) California, Minnesota, New Mexico and Hawaii.

End Use Energy Efficiency

AEP has reduced energy consumption and peak demand through the introduction of additional energy efficiency and demand response programs. These programs, commonly and collectively referred to as demand side management, were implemented in jurisdictions where appropriate cost recovery was available. AEP's operating companies' programs have reduced annual consumption by over 8 million MWhs and peak demand by approximately 2,555 MWs since 2008. AEP estimates that its operating companies spent approximately $1.4 billion during that period to achieve these levels.

Energy efficiency and demand reduction programs have received regulatory support in most of the states AEP serves. Appropriate cost recovery will be essential for AEP operating companies to continue and expand these consumer offerings. Appropriate recovery of program costs, lost revenues and an opportunity to earn a reasonable return ensures that energy efficiency programs are considered equally with supply side investments. As AEP continues to transition to a cleaner, more efficient energy future, energy efficiency and demand response programs will continue to play an important role in how the company serves its customers. AEP believes its experience providing robust energy efficiency programs in several states positions the company to be a cost-effective provider of these programs as states develop their implementation plans.

Corporate Governance

In response to environmental issues and in connection with its assessment of AEP's strategic plan, the Board of Directors continually reviews the risks posed by new environmental rules and requirements that could accelerate the retirement of coal-fired generation assets. The Board of Directors is informed of any new environmental regulations and proposed regulation or legislation that would significantly affect the company. The Board's Committee on Directors and Corporate Governance oversees the company's annual Corporate Accountability Report, which includes information about the company's environmental, social, governance and financial performance. In addition, as a result of ongoing corporate governance outreach efforts with shareholders, AEP set new CO_2 emission reduction goals that were published in a new report in February 2018, "American Electric Power: Strategic Vision for a Clean Energy Future."

Other Environmental Issues and Matters

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 imposes costs for environmental remediation upon owners and previous owners of sites, as well as transporters and generators of hazardous material disposed of at such sites. See "The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation" section of Note 6 included in the 2018 Annual Report for additional information.

Environmental Investments

Investments related to improving AEP System plants' environmental performance and compliance with air and water quality standards during 2016, 2017 and 2018 and the current estimate for 2019 are shown below. These investments include both environmental as well as other related spending. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends and the ability to access capital. In addition to the amounts set forth below, AEP expects to make substantial investments in future years in connection with the modification and addition at generation plants' facilities for environmental quality controls. Such future investments are needed in order to comply with air and water quality standards that have been adopted and have deadlines for compliance after 2018 or have been proposed and may be adopted. Future investments could be significantly greater if emissions reduction requirements are accelerated or otherwise become more stringent. The cost of complying with applicable environmental laws, regulations and rules is expected to be material to the AEP System. AEP typically recovers costs of complying with environmental standards from customers through rates in regulated jurisdictions. Failure to recover these costs could reduce future net income and cash flows and possibly harm AEP's financial condition. See "Environmental Issues" section of Management's Discussion and Analysis of Financial

Condition and Results of Operations and Note 6 - Commitments, Guarantees and Contingencies included in the 2018 Annual Report for additional information.

Historical and Projected Environmental Investments

	2016 Actual	2017 Actual	2018 Actual	2019 Estimate (b)
		(in millions)		
AEP (a)	$ 383.7	$ 135.9	$ 115.6	$ 237.7
APCo	50.0	25.6	20.4	32.7
I&M	65.0	41.9	31.1	76.8
PSO	34.8	0.6	—	2.5
SWEPCo	82.1	11.7	14.1	25.1

(a) Includes expenditures of the subsidiaries shown and other subsidiaries not shown. The figures reflect construction expenditures, not investments in subsidiary companies.
(b) Estimated amounts are exclusive of debt AFUDC.

Management continues to refine the cost estimates of complying with air and water quality standards and other impacts of the environmental proposals. The following cost estimates for the years 2019 through 2025 will change depending on the timing of implementation and whether the Federal EPA provides flexibility in the final rules. These cost estimates will also change based on: (a) the states' implementation of these regulatory programs, including the potential for SIPs or FIPs that impose more stringent standards, (b) additional rulemaking activities in response to court decisions, (c) the actual performance of the pollution control technologies installed on the units, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired, replaced or sold, including the type and amount of such replacement capacity and (g) other factors. Management's current ranges of estimates of new major environmental investments beginning in 2019, exclusive of debt AFUDC, are set forth below:

	Projected (2019 - 2025) Environmental Investment	
Company	Low	High
	(in millions)	
AEP	$ 650	$ 1,500
APCo	135	240
I&M	105	200
PSO	15	45
SWEPCo	140	230

BUSINESS SEGMENTS

AEP's Reportable Segments

AEP's primary business is the generation, transmission and distribution of electricity. Within its Vertically Integrated Utilities segment, AEP centrally dispatches generation assets and manages its overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements. AEP's reportable segments are as follows:

- Vertically Integrated Utilities
- Transmission and Distribution Utilities
- AEP Transmission Holdco
- Generation & Marketing

The remainder of AEP's activities is presented as Corporate and Other, which is not considered a reportable segment. See Note 9 - Business Segments included in the 2018 Annual Report for additional information on AEP's segments.

VERTICALLY INTEGRATED UTILITIES

GENERAL

AEP's vertically integrated utility operations are engaged in the generation, transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEGCo, APCo, I&M, KGPCo, KPCo, PSO, SWEPCo and WPCo. AEPSC, as agent for AEP's public utility subsidiaries, performs marketing, generation dispatch, fuel procurement and power-related risk management and trading activities on behalf of each of these subsidiaries.

ELECTRIC GENERATION

Facilities

As of December 31, 2018, AEP's vertically integrated public utility subsidiaries owned or leased approximately 23,000 MWs of domestic generation. See Item 2 – Properties for more information regarding the generation capacity of vertically integrated public utility subsidiaries.

Fuel Supply

The following table shows the owned and leased generation sources by type (including wind purchase agreements), on an actual net generation (MWhs) basis, used by the Vertically Integrated Utilities:

	2018	2017	2016
Coal and Lignite	58%	61%	61%
Nuclear	18%	18%	16%
Natural Gas	14%	11%	13%
Renewables	10%	10%	10%

A price increase/decrease in one or more fuel sources relative to other fuels, as well as the addition of renewable resources, may result in the decreased/increased use of other fuels. AEP's overall 2018 fossil fuel costs for the Vertically Integrated Utilities remained flat on a dollar per MMBtu basis from 2017.

Coal and Lignite

AEP's Vertically Integrated Utilities procure coal and lignite under a combination of purchasing arrangements including long-term contracts, affiliate operations and spot agreements with various producers, marketers and coal trading firms. Coal consumption in 2018 decreased approximately 2% from 2017.

Management believes that the Vertically Integrated Utilities will be able to secure and transport coal and lignite of adequate quality and in adequate quantities to operate their coal and lignite-fired units. Through subsidiaries, AEP owns, leases or controls more than 3,664 railcars, 468 barges, 9 towboats and a coal handling terminal with approximately 18 million tons of annual capacity to move and store coal for use in AEP generating facilities.

Spot market prices for coal started to strengthen in the second half of 2018. The increased spot coal prices reflect tighter supplies and increased demand for export coal. As of December 31, 2018, approximately half of the coal purchased by AEP's subsidiaries was procured through term contracts. As those contracts expire or re-open for price adjustments, needed tonnage is replaced at current market prices as necessary. The price impact of this process is reflected in subsequent periods. The price paid for coal delivered in 2018 decreased approximately 2% from 2017.

The following table shows the amount of coal and lignite delivered to the Vertically Integrated Utilities' plants during the past three years and the average delivered price of coal purchased by the Vertically Integrated Utilities:

	2018	2017	2016
Total coal delivered to the plants (millions of tons)	29.0	29.3	30.0
Average cost per ton of coal delivered	$ 43.21	$ 44.24	$ 45.92

The coal supplies at the Vertically Integrated Utilities plants vary from time to time depending on various factors, including, but not limited to, demand for electric power, unit outages, transportation infrastructure limitations, space limitations, plant coal consumption rates, availability of acceptable coals, labor issues and weather conditions, which may interrupt production or deliveries. As of December 31, 2018, the Vertically Integrated Utilities' coal inventory was approximately 32 days of full load burn. While inventory targets vary by plant and are changed as necessary, the current coal inventory target for the Vertically Integrated Utilities is approximately 30 days.

Natural Gas

The Vertically Integrated Utilities consumed approximately 112 billion cubic feet of natural gas during 2018 for generating power. This represents an increase of 29% from 2017. Total gas consumption for the Vertically Integrated Utilities was higher year over year primarily due to lower natural gas prices and increased demand for electricity. Several of AEP's natural gas-fired power plants are connected to at least two pipelines which allow greater access to competitive supplies and improve delivery reliability. A portfolio of term, monthly, seasonal and daily supply and transportation agreements provide natural gas requirements for each plant, as appropriate. AEP's natural gas supply agreements are entered into on a competitive basis and based on market prices.

The following table shows the amount of natural gas delivered to the Vertically Integrated Utilities' plants during the past three years and the average delivered price of natural gas purchased by the Vertically Integrated Utilities.

	2018	2017	2016
Total natural gas delivered to the plants (billion of cubic feet)	111.6	86.3	103.9
Average price per MMBtu of purchased natural gas	$ 3.26	$ 3.37	$ 2.77

Nuclear

I&M has made commitments to meet the current nuclear fuel requirements of the Cook Plant. I&M has made and will make purchases of uranium in various forms in the spot, short-term and mid-term markets. I&M also continues to finance its nuclear fuel through leasing.

For purposes of the storage of high-level radioactive waste in the form of SNF, I&M completed modifications to its SNF storage pool in the early 1990's. I&M entered into an agreement to provide for onsite dry cask storage of SNF to permit normal operations to continue. I&M is scheduled to conduct further dry cask loading and storage projects on an ongoing periodic basis. I&M completed its initial loading of SNF into the dry casks in 2012, which consisted of 12 casks (32 SNF assemblies contained within each). The second loading of SNF into dry casks, which consisted of 16 casks, was completed in 2015. The third dry cask loading campaign, which also consisted of 16 casks, was completed in 2018.

Nuclear Waste and Decommissioning

As the owner of the Cook Plant, I&M has a significant future financial commitment to dispose of SNF and decommission and decontaminate the plant safely. The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. The most recent decommissioning cost study was completed in 2018. The estimated cost of decommissioning and disposal of low-level radioactive waste for the Cook Plant was $2 billion in 2018 non-discounted dollars, with additional ongoing estimated costs of $6 million per year for post decommissioning storage of SNF and an eventual estimated cost of $37 million for the subsequent decommissioning of the spent fuel storage facility, also

in 2018 non-discounted dollars. As of December 31, 2018 and 2017, the total decommissioning trust fund balance for the Cook Plant was approximately $2.2 billion. The balance of funds available to eventually decommission Cook Plant will differ based on contributions and investment returns. The ultimate cost of retiring the Cook Plant may be materially different from estimates and funding targets as a result of the:

- Escalation of various cost elements (including, but not limited to, general inflation and the cost of energy).
- Further development of regulatory requirements governing decommissioning.
- Technology available at the time of decommissioning differing significantly from that assumed in studies.
- Availability of nuclear waste disposal facilities.
- Availability of a United States Department of Energy facility for permanent storage of SNF.

Accordingly, management is unable to provide assurance that the ultimate cost of decommissioning the Cook Plant will not be significantly different than current projections. AEP will seek recovery from customers through regulated rates if actual decommissioning costs exceed projections. See the "Nuclear Contingencies" section of Note 6 - Commitments, Guarantees and Contingencies included in the 2018 Annual Report for information with respect to nuclear waste and decommissioning.

Low-Level Radioactive Waste

The Low-Level Waste Policy Act of 1980 mandates that the responsibility for the disposal of low-level radioactive waste rests with the individual states. Low-level radioactive waste consists largely of ordinary refuse and other items that have come in contact with radioactive materials. Michigan does not currently have a disposal site for such waste available. I&M cannot predict when such a site may be available. However, the states of Utah and Texas have licensed low level radioactive waste disposal sites which currently accept low level radioactive waste from Michigan waste generators. There is currently no set date limiting I&M's access to either of these facilities. The Cook Plant has a facility onsite designed specifically for the storage of low level radioactive waste. In the event that low level radioactive waste disposal facility access becomes unavailable, it can be stored onsite at this facility.

Counterparty Risk Management

The Vertically Integrated Utilities segment also sells power and enters into related energy transactions with wholesale customers and other market participants. As a result, counterparties and exchanges may require cash or cash related instruments to be deposited on transactions as margin against open positions. As of December 31, 2018, counterparties posted approximately $9 million in cash, cash equivalents or letters of credit with AEPSC for the benefit of AEP's public utility subsidiaries (while, as of that date, AEP's public utility subsidiaries posted approximately $54 million with counterparties and exchanges). Since open trading contracts are valued based on market prices of various commodities, exposures change daily. See the "Quantitative and Qualitative Disclosures About Market Risk" section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in the 2018 Annual Report for additional information.

Certain Power Agreements

I&M

The UPA between AEGCo and I&M, dated March 31, 1982, provides for the sale by AEGCo to I&M of all the capacity (and the energy associated therewith) available to AEGCo at the Rockport Plant. Whether or not power is available from AEGCo, I&M is obligated to pay a demand charge for the right to receive such power (and an energy charge for any associated energy taken by I&M). The agreement will continue in effect until the last of the lease terms of Unit 2 of the Rockport Plant have expired (currently December 2022) unless extended in specified circumstances.

Pursuant to an assignment between I&M and KPCo, and a UPA between AEGCo and KPCo, AEGCo sells KPCo 30% of the capacity (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo has agreed to pay to AEGCo the amounts that I&M would have paid AEGCo under the terms of the UPA between AEGCo and I&M for such entitlement. The KPCo UPA expires in December 2022.

OVEC

AEP and several nonaffiliated utility companies jointly own OVEC. The aggregate equity participation of AEP in OVEC is 43.47%. Parent owns 39.17% and OPCo owns 4.3%. Under the Inter-Company Power Agreement (ICPA), which defines the rights of the owners and sets the power participation ratio of each, the sponsoring companies are entitled to receive and are obligated to pay for all OVEC capacity (approximately 2,400 MWs) in proportion to their respective power participation ratios. The aggregate power participation ratio of APCo, I&M and OPCo is 43.47%. The ICPA terminates in June 2040. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs. AEP and the other owners have authorized environmental investments related to their ownership interests. OVEC financed capital expenditures totaling $1.3 billion in connection with flue gas desulfurization projects and the associated scrubber waste disposal landfills at its two generation plants through debt issuances, including tax-advantaged debt issuances. Both OVEC generation plants are operating with the new environmental controls in service. OPCo attempted to assign its rights and obligations under the ICPA to an affiliate as part of its transfer of its generation assets and liabilities in keeping with corporate separation required by Ohio law. OPCo failed to obtain the consent to assignment from the other owners of OVEC and therefore filed a request with the PUCO seeking authorization to maintain its ownership of OVEC. In December 2013, the PUCO approved OPCo's request, subject to the condition that energy from the OVEC entitlements are sold into the day-ahead or real-time PJM energy markets, or on a forward basis through a bilateral arrangement. In November 2016, the PUCO approved OPCo's request to approve a cost-based purchased power agreement (PPA) rider, effective in January 2017, that would initially be based upon OPCo's contractual entitlement under the ICPA which is approximately 20% of OVEC's capacity. In late 2016, two nonaffiliated parties to the ICPA owned by First Energy Corp. announced their intention to exit its merchant business and that it may pursue restructuring or bankruptcy. In March 2018 FirstEnergy Solutions ("FES"), with an aggregate power participation ratio of approximately 5% under the ICPA, filed bankruptcy. In July 2018, the Bankruptcy Court granted FES's motion to reject the ICPA. OVEC is currently appealing this decision in the United States Court of Appeals for the Sixth Circuit. If OVEC does not have sufficient funds to honor its payment obligations, there is risk that APCo, I&M and/or OPCo may need to make payments in addition to their power participation ratio payments. Further, if OVEC's indebtedness is accelerated for any reason, there is risk that APCo, I&M and/or OPCo may be required to pay some or all of such accelerated indebtedness in amounts equal to their aggregate power participation ratio of 43.47%. The foregoing and other related actions have adversely impacted the credit ratings of OVEC.

ELECTRIC DELIVERY

General

Other than AEGCo, AEP's vertically integrated public utility subsidiaries own and operate transmission and distribution lines and other facilities to deliver electric power. See Item 2 – Properties for more information regarding the transmission and distribution lines. Most of the transmission and distribution services are sold to retail customers of AEP's vertically integrated public utility subsidiaries in their service territories. These sales are made at rates approved by the state utility commissions of the states in which they operate, and in some instances, approved by the FERC. See Item 1. Business – Vertically Integrated Utilities – Regulation – Rates. The FERC regulates and approves the rates for both wholesale transmission transactions and wholesale generation contracts. The use and the recovery of costs associated with the transmission assets of the AEP vertically integrated public utility subsidiaries are subject to the rules, principles, protocols and agreements in place with PJM and SPP, and as approved by the FERC. See Item 1. Business – Vertically Integrated Utilities – Regulation – FERC. As discussed below, some transmission services also are separately sold to nonaffiliated companies.

Other than AEGCo, AEP's vertically integrated public utility subsidiaries hold franchises or other rights to provide electric service in various municipalities and regions in their service areas. In some cases, these franchises provide the utility with the exclusive right to provide electric service within a specific territory. These franchises have varying provisions and expiration dates. In general, the operating companies consider their franchises to be adequate for the conduct of their business. For a discussion of competition in the sale of power, see Item 1. Business – Vertically Integrated Utilities – Competition.

Transmission Agreement (TA)

APCo, I&M, KGPCo, KPCo and WPCo own and operate transmission facilities that are used to provide transmission service under the PJM OATT and are parties to the TA. OPCo, which is a subsidiary in AEP's Transmission and Distribution Utilities segment that provides transmission service under the PJM OATT, is also a party to the TA. The TA defines how the parties to the agreement share the revenues associated with their transmission facilities and the costs of transmission service provided by PJM. The TA has been approved by the FERC.

TCA and OATT

PSO, SWEPCo and AEPSC are parties to the TCA. Under the TCA, a coordinating committee is charged with the responsibility of (a) overseeing the coordinated planning of the transmission facilities of the parties to the agreement, including the performance of transmission planning studies, (b) the interaction of such subsidiaries with independent system operators and other regional bodies interested in transmission planning and (c) compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such tariff. Pursuant to the TCA, AEPSC has responsibility for monitoring the reliability of their transmission systems and administering the OATT on behalf of the other parties to the agreement. The TCA also provides for the allocation among the parties of revenues collected for transmission and ancillary services provided under the OATT. These allocations have been determined by the FERC-approved OATT for the SPP.

Regional Transmission Organizations

AEGCo, APCo, I&M, KGPCo, KPCo and WPCo are members of PJM, and PSO and SWEPCo are members of SPP (both FERC-approved RTOs). RTOs operate, plan and control utility transmission assets in a manner designed to provide open access to such assets in a way that prevents discrimination between participants owning transmission assets and those that do not.

REGULATION

General

AEP's vertically integrated public utility subsidiaries' retail rates and certain other matters are subject to traditional cost-based regulation by the state utility commissions. AEP's vertically integrated public utility subsidiaries are also subject to regulation by the FERC under the Federal Power Act with respect to wholesale power and transmission service transactions. I&M is subject to regulation by the NRC under the Atomic Energy Act of 1954, as amended, with respect to the operation of the Cook Plant. AEP and its vertically integrated public utility subsidiaries are also subject to the regulatory provisions of, much of the Energy Policy Act of 2005, which is administered by the FERC.

Rates

Historically, state utility commissions have established electric service rates on a cost-of-service basis, which is designed to allow a utility an opportunity to recover its cost of providing service and to earn a reasonable return on its investment used in providing that service. A utility's cost of service generally reflects its operating expenses, including operation and maintenance expense, depreciation expense and taxes. State utility commissions periodically adjust rates pursuant to a review of (a) a utility's adjusted revenues and expenses during a defined test period and (b) such utility's level of investment. Absent a legal limitation, such as a law limiting the frequency of rate changes or capping rates for a period

of time, a state utility commission can review and change rates on its own initiative. Some states may initiate reviews at the request of a utility, customer, governmental or other representative of a group of customers. Such parties may, however, agree with one another not to request reviews of or changes to rates for a specified period of time.

Public utilities have traditionally financed capital investments until the new asset is placed in service. Provided the asset was found to be a prudent investment, it was then added to rate base and entitled to a return through rate recovery. Given long lead times in construction, the high costs of plant and equipment and volatile capital markets, management actively pursues strategies to accelerate rate recognition of investments and cash flow. AEP representatives continue to engage state commissioners and legislators on alternative ratemaking options to reduce regulatory lag and enhance certainty in the process. These options include pre-approvals, a return on construction work in progress, rider/trackers, formula rates and the inclusion of future test-year projections into rates.

The rates of AEP's vertically integrated public utility subsidiaries are generally based on the cost of providing traditional bundled electric service (i.e., generation, transmission and distribution service). Historically, the state regulatory frameworks in the service area of the AEP vertically integrated public utility subsidiaries reflected specified fuel costs as part of bundled (or, more recently, unbundled) rates or incorporated fuel adjustment clauses in a utility's rates and tariffs. Fuel adjustment clauses permit periodic adjustments to fuel cost recovery from customers and therefore provide protection against exposure to fuel cost changes.

The following state-by-state analysis summarizes the regulatory environment of certain major jurisdictions in which AEP's vertically integrated public utility subsidiaries operate. Several public utility subsidiaries operate in more than one jurisdiction. See Note 4 - Rate Matters included in the 2018 Annual Report for more information regarding pending rate matters.

Indiana

I&M provides retail electric service in Indiana at bundled rates approved by the IURC, with rates set on a cost-of-service basis. Indiana provides for timely fuel and purchased power cost recovery through a fuel cost recovery mechanism.

Oklahoma

PSO provides retail electric service in Oklahoma at bundled rates approved by the OCC. PSO's rates are set on a cost-of-service basis. Fuel and purchased energy costs are recovered or refunded by applying fuel adjustment and other factors to retail kilowatt-hour sales.

Virginia

APCo currently provides retail electric service in Virginia at unbundled generation and distribution rates approved by the Virginia SCC. Virginia generally allows for timely recovery of fuel costs through a fuel adjustment clause. In addition to base rates and fuel cost recovery, APCo is permitted to recover a variety of costs through rate adjustment clauses including transmission services provided at OATT rates based on rates established by the FERC.

West Virginia

APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC, with rates set on a combined cost-of-service basis. West Virginia generally allows for timely recovery of fuel costs through an expanded net energy cost which trues-up to actual expenses.

FERC

The FERC regulates rates for interstate power sales at wholesale, transmission of electric power, accounting and other matters, including construction and operation of hydroelectric projects. The FERC regulations require AEP's vertically integrated public utility subsidiaries to provide open access transmission service at FERC-approved rates, and AEP has approved cost-based formula transmission rates on file at the FERC. The FERC also regulates unbundled transmission service to retail customers. In addition, the FERC regulates the sale of power for resale in interstate commerce by (a) approving contracts for wholesale sales to municipal and cooperative utilities and (b) granting authority to public utilities to sell power at wholesale at market-based rates upon a showing that the seller lacks the ability to improperly influence market prices. AEP's vertically integrated public utility subsidiaries have market-based rate authority from the FERC, under which much of their wholesale marketing activity takes place. The FERC requires each public utility that owns or controls interstate transmission facilities to, directly or through an RTO, to file an open access network and point-to-point transmission tariff that offers services comparable to the utility's own uses of its transmission system. The FERC also requires all transmitting utilities, directly or through an RTO, to establish an Open Access Same-time Information System, which electronically posts transmission information such as available capacity and prices, and requires utilities to comply with Standards of Conduct that prohibit utilities' transmission employees from providing non-public transmission information to the utility's marketing employees. Additionally, the vertically integrated public utility subsidiaries are subject to reliability standards promulgated by the North American Electric Reliability Corporation, with the approval of the FERC.

The FERC oversees RTOs, entities created to operate, plan and control utility transmission assets. AEGCo, APCo, I&M, KGPCo, KPCo and WPCo are members of PJM. PSO and SWEPCo are members of SPP.

The FERC has jurisdiction over the issuances of securities of most of AEP's public utility subsidiaries, the acquisition of securities of utilities, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. In addition, both the FERC and state regulators are permitted to review the books and records of any company within a holding company system.

COMPETITION

Other than AEGCo, AEP's vertically integrated public utility subsidiaries generate, transmit and distribute electricity to retail customers of AEP's vertically integrated public utility subsidiaries in their service territories. These sales are made at rates approved by the state utility commissions of the states in which they operate, and in some instances, approved by the FERC, and are not subject to competition from other vertically integrated public utilities. Other than AEGCo, AEP's vertically integrated public utility subsidiaries hold franchises or other rights that effectively grant the exclusive ability to provide electric service in various municipalities and regions in their service areas.

AEP's vertically integrated public utility subsidiaries compete with self-generation and with distributors of other energy sources, such as natural gas, fuel oil, renewables and coal, within their service areas. The primary factors in such competition are price, reliability of service and the capability of customers to utilize alternative sources of energy other than electric power. With respect to competing generators and self-generation, the public utility subsidiaries of AEP believe that they currently maintain a competitive position.

Changes in regulatory policies and advances in newer technologies for batteries or energy storage, fuel cells, microturbines, wind turbines and photovoltaic solar cells are reducing costs of new technology to levels that are making them competitive with some central station electricity production. The costs of photovoltaic solar cells in particular have continued to become increasingly competitive. The ability to maintain relatively low cost, efficient and reliable operations and to provide cost-effective programs and services to customers are significant determinants of AEP's competitiveness.

SEASONALITY

The consumption of electric power is generally seasonal. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. The pattern of this fluctuation may change due to the nature and location of AEP's facilities and the terms of power sale contracts into which AEP enters. In addition, AEP has historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish AEP's results of operations. Conversely, unusually extreme weather conditions could increase AEP's results of operations.

TRANSMISSION AND DISTRIBUTION UTILITIES

GENERAL

This segment consists of the transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEP Texas and OPCo. OPCo is engaged in the transmission and distribution of electric power to approximately 1,486,000 retail customers in Ohio. OPCo purchases energy and capacity at auction to serve generation service customers who have not switched to a competitive generation supplier. AEP Texas is engaged in the transmission and distribution of electric power to approximately 1,050,000 retail customers through REPs in west, central and southern Texas.

AEP's transmission and distribution utility subsidiaries own and operate transmission and distribution lines and other facilities to deliver electric power. See Item 2 – Properties, for more information regarding the transmission and distribution lines. Transmission and distribution services are sold to retail customers of AEP's transmission and distribution utility subsidiaries in their service territories. These sales are made at rates approved by the PUCT for AEP Texas and by the PUCO and the FERC for OPCo. The FERC regulates and approves the rates for wholesale transmission transactions. As discussed below, some transmission services also are separately sold to nonaffiliated companies.

AEP's transmission and distribution utility subsidiaries hold franchises or other rights to provide electric service in various municipalities and regions in their service areas. In some cases, these franchises provide the utility with the exclusive right to provide electric service. These franchises have varying provisions and expiration dates. In general, the operating companies consider their franchises to be adequate for the conduct of their business.

The use and the recovery of costs associated with the transmission assets of the AEP transmission and distribution utility subsidiaries are subject to the rules, protocols and agreements in place with PJM and ERCOT, and as approved by the FERC. In addition to providing transmission services in connection with power sales in their service areas, AEP's transmission and distribution utility subsidiaries also provide transmission services for nonaffiliated companies through RTOs.

Transmission Agreement

OPCo owns and operates transmission facilities that are used to provide transmission service under the PJM OATT; OPCo is a party to the TA with other utility subsidiary affiliates. The TA defines how the parties to the agreement share the revenues associated with their transmission facilities and the costs of transmission service provided by PJM. The TA has been approved by the FERC.

Regional Transmission Organizations

OPCo is a member of PJM, a FERC-approved RTO. RTOs operate, plan and control utility transmission assets to provide open access to such assets in a way that prevents discrimination between participants owning transmission assets and those that do not. AEP Texas is a member of ERCOT.

REGULATION

OPCo provides distribution and transmission services to retail customers within its service territory at cost-based rates approved by the PUCO or by the FERC. AEP Texas provides transmission and distribution service on a cost-of-service basis at rates approved by the PUCT and wholesale transmission service under tariffs approved by the FERC consistent with PUCT rules. Transmission and distribution rates are established on a cost-of-service basis, which is designed to allow a utility an opportunity to recover its cost of providing service and to earn a reasonable return on its investment used in providing that service. The cost of service generally reflects operating expenses, including operation and maintenance expense, depreciation expense and taxes. Utility commissions periodically adjust rates pursuant to a review of: (a) a utility's adjusted revenues and expenses during a defined test period and (b) such utility's level of investment.

FERC

The FERC regulates rates for transmission of electric power, accounting and other matters. The FERC regulations require AEP to provide open access transmission service at FERC-approved rates, and it has approved cost-based formula transmission rates on file at the FERC. The FERC also regulates unbundled transmission service to retail customers. The FERC requires each public utility that owns or controls interstate transmission facilities to, directly or through an RTO, file an open access network and point-to-point transmission tariff that offers services comparable to the utility's own uses of its transmission system. The FERC also requires all transmitting utilities, directly or through an RTO, to establish an Open Access Same-time Information System, which electronically posts transmission information such as available capacity and prices, and requires utilities to comply with Standards of Conduct that prohibit utilities' transmission employees from providing non-public transmission information to the utility's marketing employees. In addition, both the FERC and state regulators are permitted to review the books and records of any company within a holding company system. Additionally, the transmission and distribution utility subsidiaries are subject to reliability standards as set forth by the North American Electric Reliability Corporation, with the approval of the FERC.

SEASONALITY

The delivery of electric power is generally seasonal. In many parts of the country, demand for power peaks during the hot summer months. In other areas, power demand peaks during the winter months. The pattern of this fluctuation may change due to the nature and location of AEP's transmission and distribution facilities. In addition, AEP transmission and distribution has historically delivered less power, and consequently earned less income, when weather conditions are milder. In Texas, and to a lesser extent, in Ohio, where there is residential decoupling, unusually mild weather in the future could diminish AEP's results of operations. Conversely, unusually extreme weather conditions could increase AEP's results of operations.

AEP TRANSMISSION HOLDCO

GENERAL

AEPTHCo is a holding company for (a) AEPTCo, which is the direct holding company for the State Transcos and (b) AEP's Transmission Joint Ventures.

AEPTCo

AEPTCo wholly owns the State Transcos:

- AEP Appalachian Transmission Company, Inc. (APTCo)
- AEP Indiana Michigan Transmission Company, Inc. (IMTCo)
- AEP Kentucky Transmission Company, Inc. (KTCo)
- AEP Ohio Transmission Company, Inc. (OHTCo)
- AEP West Virginia Transmission Company, Inc. (WVTCo)
- AEP Oklahoma Transmission Company, Inc. (OKTCo)
- AEP Southwestern Transmission Company, Inc. (SWTCo)

The State Transcos are independent of, but respectively overlay, the following AEP electric utility operating companies: APCo, I&M, KPCo, KGPCo, OPCo, PSO, SWEPCo, and WPCo. The State Transcos develop, own, operate, and maintain their respective transmission assets. Assets of the State Transcos interconnect to transmission facilities owned by the aforementioned operating companies and nonaffiliated transmission owners within the footprints of PJM, MISO and SPP. APTCo, IMTCo, KTCo, OHTCo, and WVTCo are located within PJM. IMTCo also owns portions of the Greentown station assets located in MISO. OKTCo and SWTCo are located within SPP.

IMTCo, KTCo, OHTCo, OKTCo, and WVTCo own and operate transmission assets in their respective jurisdictions. In December 2016, the Virginia SCC and WVPSC granted consent for APCo and APTCo to enter into a joint license agreement that will support APTCo investment in the state of Tennessee. SWTCo does not currently own or operate transmission assets.

The State Transcos are regulated for rate-making purposes exclusively by the FERC and earn revenues through tariff rates charged for the use of their electric transmission systems. The State Transcos establish transmission rates each year through formula rate filings with the FERC. The rate filings calculate the revenue requirement needed to cover the costs of operation and debt service and to earn an allowed ROE. These rates are then included in an OATT for PJM, MISO and SPP.

The State Transcos own, operate, maintain and invest in transmission infrastructure in order to maintain and enhance system integrity and grid reliability, grid security, safety, reduce transmission constraints and facilitate interconnections of new generating resources and new wholesale customers, as well as enhance competitive wholesale electricity markets. A key part of AEP's business is replacing and upgrading transmission facilities, assets and components of the existing AEP System as needed to maintain reliability.

The State Transcos provide the capability to replace and upgrade existing facilities. As of December 31, 2018, the State Transcos had \$6.7 billion of transmission and other assets in-service with plans to construct approximately \$4.5 billion of additional transmission assets through 2021. Additional investment in transmission infrastructure is needed within PJM and SPP to maintain the required level of grid reliability, resiliency, security and efficiency and to address an aging transmission infrastructure. Additional transmission facilities will be needed based on changes in generating resources, such as wind or solar projects, generation additions or retirements, and additional new customer interconnections. The State Transcos will continue their investment to enhance physical and cyber security of assets, and are also investing in improving the telecommunication network that supports the operation and control of the grid.

AEPTHCO JOINT VENTURE INITIATIVES

AEP has established joint ventures with other electric utility companies for the purpose of developing, building, and owning transmission assets that seek to improve reliability and market efficiency and provide transmission access to remote generation sources in North America (Transmission Joint Ventures).

The Transmission Joint Ventures currently include:

Joint Venture Name	Location	Projected or Actual Completion Date	Owners (Ownership %)	Total Estimated/Actual Project Costs at Completion		Approved Return on Equity	
				(in millions)			
ETT	Texas (ERCOT)	(a)	Berkshire Hathaway Energy (50%) AEP (50%)	$ 3,310.9	(a)	9.6%	
Prairie Wind	Kansas	2014	Westar Energy (50%) Berkshire Hathaway Energy (25%) AEP (25%) (b)	158.0		12.8%	
Pioneer	Indiana	2018	Duke Energy (50%) AEP (50%)	187.4		10.82%	
Transource Missouri	Missouri	2016	Evergy, Inc. (13.5%) (c) AEP (86.5%) (c)	310.5		11.2%	(d)
Transource West Virginia	West Virginia	2019	Evergy, Inc. (13.5%) (c) AEP (86.5%) (c)	78.1		10.5%	
Transource Maryland	Maryland	2020	Evergy, Inc. (13.5%) (c) AEP (86.5%) (c)	25.0	(e)	10.4%	(f)
Transource Pennsylvania	Pennsylvania	2020	Evergy, Inc. (13.5%) (c) AEP (86.5%) (c)	192.0	(e)	10.4%	(f)

(a) ETT is undertaking multiple projects and the completion dates will vary for those projects. ETT's investment in completed, current and future projects in ERCOT over the next ten years is expected to be $3.3 billion. Future projects will be evaluated on a case-by-case basis.

(b) AEP owns 25% of Prairie Wind Transmission, LLC (Prairie Wind) through its ownership interest in Electric Transmission America, LLC. which is a 50/50 joint venture with Berkshire Hathaway Energy (formerly known as MidAmerican Energy) and AEP.

(c) AEP owns 86.5% of Transource Missouri, Transource West Virginia, Transource Maryland and Transource Pennsylvania through its ownership interest in Transource Energy, LLC (Transource). Transource is a joint venture with AEPTHCo and Evergy, Inc. formed to pursue competitive transmission projects. AEPTHCo and Evergy, Inc. own 86.5% and 13.5% of Transource, respectively.

(d) The ROE represents the weighted average approved ROE based on the costs of two projects developed by Transource Missouri; the $64 million Iatan-Nashua project (10.3%) and the $247 million Sibley-Nebraska City project (11.3%).

(e) In August 2016, Transource Maryland and Transource Pennsylvania received approval from the PJM Interconnection Board to construct portions of a transmission project located in both Maryland and Pennsylvania. The project is expected to go in service in 2020. Project costs are in 2018 dollars.

(f) In January 2018, Transource Maryland and Transource Pennsylvania received FERC approval of a settlement authorizing an ROE of 10.4%. This reflects a 9.9% base plus 0.5% RTO participation adder.

Transource Missouri, Transource West Virginia, Transource Maryland and Transource Pennsylvania are consolidated joint ventures by AEP. All other joint ventures in the table above are not consolidated by AEP. AEP's joint ventures do not have employees. Business services for the joint ventures are provided by AEPSC and other AEP subsidiaries and the joint venture partners. During 2018, approximately 537 AEPSC employees and 283 operating company employees provided service to one or more joint ventures.

REGULATION

The State Transcos and the Transmission Joint Ventures located outside of ERCOT establish transmission rates annually through forward looking formula rate filings with the FERC pursuant to FERC-approved implementation protocols. The protocols include a transparent, formal review process to ensure the updated transmission rates are prudently incurred and reasonably calculated. The IMTCo-owned Greentown station assets acquired from Duke Energy Indiana, LLC in December 2018 are located in MISO. IMTCo plans to utilize historic costs for recovery.

The State Transcos' and the Transmission Joint Ventures' (where applicable) rates are included in the respective OATT for PJM and SPP. An OATT is the FERC rate schedule that provides the terms and conditions for transmission and related services on a transmission provider's transmission system. The FERC requires transmission providers such as PJM and SPP to offer transmission service to all eligible customers (for example, load-serving entities, power marketers, generators and customers) on a non-discriminatory basis.

The FERC-approved formula rates establish the annual transmission revenue requirement (ATRR) and transmission service rates for transmission owners in annual rate base filings with the FERC. The formula rates establish rates for a one-year period based on the current projects in-service and proposed projects for a defined timeframe. The formula rates also include a true-up calculation for the previous year's billings, allowing for over/under-recovery of the transmission owner's ATRR. PJM and SPP pay the transmission owners their ATRR for use of their facilities and bill transmission customers taking service under the PJM and SPP OATTs, based on the terms and conditions in the respective OATT for the service taken. Additionally, the State Transcos are subject to reliability standards promulgated by the North American Electric Reliability Corporation, with the approval of the FERC.

AEP's transmission owning subsidiaries within PJM and six of the complainants filed a settlement agreement with the FERC, which is awaiting FERC approval. The pending formula rate mechanism allows for a total ROE of 10.35% based on a capital structure of up to 55% equity for APTCo, IMTCo, KTCo, OHTCo and WVTCo (the East Transcos). OKTCo and SWTCo (the West Transcos) are allowed a ROE of 11.2% without a cap on the capital structure. The authorized returns on equity for the State Transcos are the FERC-authorized returns on equity in the PJM and SPP OATTs, respectively. These returns have been challenged by parties in filings before the FERC. The West Transcos' case is ongoing.

In the annual rate base filings described above, the State Transcos in aggregate filed rate base totals of $4.6 billion for 2018, $3.8 billion for 2017 and $3.2 billion for 2016. The total transmission revenue requirements filed in the ATRR, including prior year over/under-recovery of revenue and associated carrying charges, for 2018, 2017, and 2016 was $829 million, $690 million and $555 million, respectively.

The rates of ETT, which is located in ERCOT, are determined by the PUCT. ETT sets its rates through a combination of base rate cases and interim Transmission Cost of Services (TCOS) filings. ETT may file interim TCOS filings semi-annually to update its rates to reflect changes in its net invested capital.

The Transmission Joint Ventures have approved ROEs ranging from 9.6% to 12.8% based on equity capital structures ranging from 40% to 60%.

GENERATION & MARKETING

GENERAL

The AEP Generation & Marketing segment subsidiaries consist of competitive generating assets, a wholesale energy trading and marketing business and a retail supply and energy management business. The primary fossil generation subsidiary in the Generation & Marketing segment is AGR. In January 2017, AGR sold 4,143 MWs of generation capacity to a nonaffiliated third-party and terminated a 1,186 MW UPA. As of December 31, 2018, AGR owns 2,114 MWs of generating capacity. Management plans to close 39% of this generation capacity in May 2019 and 31% in May 2020. 28% of this generating capacity is operated by Buckeye Power, a nonaffiliated electric cooperative. Other subsidiaries in this segment own or have the right to receive power from additional generation assets. See Item 2 – Properties for more information regarding the generation assets of the Generation & Marketing segment. AGR is a competitive generation subsidiary.

With respect to the wholesale energy trading and marketing business, AEP Generation & Marketing segment subsidiaries enter into short-term and long-term transactions to buy or sell capacity, energy and ancillary services in ERCOT, SPP, MISO and PJM. These subsidiaries sell power into the market and engage in power, natural gas and emissions allowances risk management and trading activities.

These activities primarily involve the purchase-and-sale of electricity (and to a lesser extent, natural gas and emissions allowances) under forward contracts at fixed and variable prices. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, OTC swaps and options. The majority of forward contracts are typically settled by entering into offsetting contracts. These transactions are executed with numerous counterparties or on exchanges.

With respect to the retail supply and energy management business, AEP Energy is a retail energy supplier that supplies electricity and/or natural gas to residential, commercial, and industrial customers. AEP Energy provides various energy solutions in Illinois, Pennsylvania, Delaware, Maryland, New Jersey, Ohio and Washington, D.C. AEP Energy also provides demand-side management solutions nationwide. AEP Energy had approximately 415,000 customer accounts as of December 31, 2018.

AEP Energy Supply, LLC owns 261 MWs of wind capacity in Texas. AEP Renewables, LLC develops and/or acquires large scale renewable projects backed with long-term contracts with creditworthy counterparties. As of December 2018, AEP Renewables, LLC owns a 20 MW solar project in California, a 20 MW solar project in Utah and a 50 MW solar project in Nevada. In December 2018, AEP Renewables, LLC entered into an agreement to own an additional 227 MW of Texas wind capacity which is expected to be placed in-service in mid-2019.

AEP OnSite Partners, LLC works directly with wholesale and large retail customers to provide tailored solutions to reduce their energy costs based upon market knowledge, innovative applications of technology and deal structuring capabilities. The company targets opportunities in distributed solar, combined heat and power, energy storage, waste heat recovery, energy efficiency, peaking generation and other energy solutions that create value for customers. AEP OnSite Partners, LLC pursues and develops behind the meter projects with creditworthy customers. As of December 31, 2018, AEP OnSite Partners, LLC owned projects operating in 15 states, including approximately 85 MWs of installed solar capacity, and approximately 57 MWs of solar projects under construction.

In February 2019, AEP Clean Energy Resources, LLC signed an agreement to purchase Sempra Renewables, LLC and its 724 MWs of wind generation and battery assets for approximately $1.1 billion, subject to closing and working capital adjustments. As part of the purchase price, AEP Clean Energy Resources, LLC will pay $551 million in cash and assume $343 million of existing project debt obligations of the non-consolidated joint ventures. Additionally, the acquisition will be accompanied by the recognition of non-controlling tax equity interest of $162 million associated with certain of the acquired wind farms. The wind generation portfolio includes seven wholly or jointly-owned wind farms with long-term PPAs for 100% of their energy production. The transaction is expected to close in mid-2019 and is subject to regulatory approvals from the FERC and federal clearance pursuant to the Hart-Scott-Rodino Antitrust Improvements Act of 1976.

REGULATION

AGR is a public utility under the Federal Power Act, and is subject to the FERC's exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Under the Federal Power Act, the FERC has the authority to grant or deny market-based rates for sales of energy, capacity and ancillary services to ensure that such sales are just and reasonable. The FERC granted AGR market-based rate authority in December 2013. The FERC's jurisdiction over ratemaking also includes the authority to suspend the market-based rates of AGR and set cost-based rates if the FERC subsequently determines that it can exercise market power, create barriers to entry or engage in abusive affiliate transactions. Periodically, AGR is required to file a market power update to show that it continues to meet the FERC's standards with respect to generation market power and other criteria used to evaluate whether it continues to qualify for market-based rates. Other matters subject to the FERC jurisdiction include, but are not limited to, review of mergers, and dispositions of jurisdictional facilities and acquisitions of securities of another public utility or an existing operational generating facility.

Specific operations of AGR are also subject to the jurisdiction of various other federal, state, regional and local agencies, including federal and state environmental protection agencies. AGR is also regulated by the PUCT for transactions inside ERCOT. Additionally, AGR is subject to mandatory reliability standards promulgated by the North American Electric Reliability Corporation, with the approval of the FERC.

COMPETITION

The AEP Generation & Marketing segment subsidiaries face competition for the sale of available power, capacity and ancillary services. The principal factors of impact are electricity and fuel prices, new market entrants, construction or retirement of generating assets by others and technological advances in power generation. Because most of AGR's remaining generation is coal-fired, lower relative natural gas prices will favor competitors that have a higher concentration of natural gas fueled generation. Other factors impacting competitiveness include environmental regulation, transmission congestion or transportation constraints at or near generation facilities, inoperability or inefficiencies, outages and deactivations and retirements at generation facilities.

Technology advancements, increased demand for clean energy, changing consumer behaviors, low-priced and abundant natural gas, and regulatory and public policy reforms are among the catalysts for transformation within the industry that impact competition for AEP's Generation & Marketing segment. AGR also competes with self-generation and with distributors of other energy sources, such as natural gas, fuel oil, renewables and coal, within their service areas. The primary factors in such competition are price, unit availability and the capability of customers to utilize sources of energy other than electric power.

Changes in regulatory policies and advances in newer technologies for batteries or energy storage, fuel cells, microturbines, wind turbines and photovoltaic solar cells are reducing costs of new technology to levels that are making them competitive with some central station electricity production. The ability to maintain relatively low cost, efficient and reliable operations and to provide cost-effective programs and services to customers are significant determinants of AGR's competitiveness. The costs of photovoltaic solar cells in particular have continued to become increasingly competitive.

In the event that alternative generation resources are mandated, subsidized or encouraged through climate legislation or regulation or otherwise are economically competitive and added to the available generation supply, such resources could displace a higher marginal cost fossil plant, which could reduce the price at which market participants sell their electricity. These events could cause AGR to retire generating capacity prior to the end of its estimated useful life.

This segment's retail operations provide competitive electricity and natural gas in deregulated retail energy markets in six states and Washington, D.C. Each such retail choice jurisdiction establishes its own laws and regulations governing its competitive market, and public utility commission communications and utility default service pricing can affect customer participation in retail competition. Sustained low natural gas and power prices, low market volatility and maturing competitive environments can adversely affect this business.

This segment also engages in procuring and selling output from renewable generation sources under long-term contracts to creditworthy counterparties. New sources are not acquired without first securing a long-term placement of such

power. Existing sources do not face competitive exposure. Competitive nonaffiliated suppliers of renewable or other generation could limit opportunities for future transactions for new sources and related output contracts.

SEASONALITY

The consumption of electric power is generally seasonal. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter months. The pattern of this fluctuation may change.

Fuel Supply

The following table shows the generation sources by type, on an actual net generation (MWhs) basis, used by the Generation & Marketing segment, not including AEP Energy Partners' offtake agreement from the Oklaunion Power Station:

	2018	2017	2016
Coal	88%	85%	62%
Natural Gas	—%	8%	36%
Renewables	12%	7%	2%

Coal and Consumables

AGR procures coal and consumables needed to burn the coal under a combination of purchasing arrangements including long-term and spot contracts with various producers and coal trading firms. As contracts expire, they are replaced, as needed, with contracts at market prices. Coal and consumable inventories remain adequate to meet generation requirements.

Management believes that AGR will be able to secure and transport coal and consumables of adequate quality and in adequate quantities to operate their coal fired units. AGR, through its contracts with third party transporters, has the ability to adequately move and store coal and consumables for use in its generating facilities. AGR plants consumed 3 million tons of coal in 2018.

The coal supplies at AGR plants vary from time to time depending on various factors, including, but not limited to, demand for electric power, unit outages, transportation infrastructure limitations, space limitations, plant coal consumption rates, coal quality, availability of acceptable coals, labor issues and weather conditions, which may interrupt production or deliveries. AGR aims to maintain the coal inventory of its managed plants in the range of 15 to 40 days of full load burn. As of December 31, 2018, the coal inventory of AGR was within the target range.

Counterparty Risk Management

Counterparties and exchanges may require cash or cash related instruments to be deposited on these transactions as margin against open positions. As of December 31, 2018, counterparties posted approximately $22 million in cash, cash equivalents or letters of credit with AEP for the benefit of AEP's Generation & Marketing segment subsidiaries (while, as of that date, AEP's Generation & Marketing segment subsidiaries posted approximately $101 million with counterparties and exchanges). Since open trading contracts are valued based on market prices of various commodities, exposures change daily. See the "Quantitative and Qualitative Disclosures About Market Risk" section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in the 2018 Annual Report for additional information.

Certain Power Agreements

As of December 31, 2018, the assets utilized in this segment included approximately 261 MWs of company-owned domestic wind power facilities, 177 MWs of domestic wind power from long-term purchase power agreements and 355 MWs of coal-fired capacity which was obtained through an agreement effective through 2027 that transfers the interest of AEP Texas in the Oklaunion Power Station to AEPEP. Management has announced plans to close Oklaunion Power Station by October 2020. The power obtained from the Oklaunion Power Station is marketed and sold in ERCOT.

EXECUTIVE OFFICERS OF AEP

The following persons are executive officers of AEP. Their ages are given as of February 21, 2019. The officers are appointed annually for a one-year term by the board of directors of AEP.

Nicholas K. Akins
Chairman of the Board, President and Chief Executive Officer
Age 58
Chairman of the Board since January 2014, President since January 2011 and Chief Executive Officer since November 2011.

Lisa M. Barton
Executive Vice President - Utilities
Age 53
Executive Vice President - Transmission from August 2011 to December 2018.

Paul Chodak, III
Executive Vice President - Generation
Age 55
Executive Vice President - Utilities from January 2017 to December 2018. President and Chief Operating Officer of I&M from July 2010 to December 2016.

David M. Feinberg
Executive Vice President, General Counsel and Secretary
Age 49
Executive Vice President since January 2013.

Lana L. Hillebrand
Executive Vice President and Chief Administrative Officer
Age 58
Chief Administrative Officer since December 2012 and Senior Vice President from December 2012 to December 2016.

Mark C. McCullough
Executive Vice President - Transmission
Age 59
Executive Vice President - Generation from January 2011 to December 2018.

Charles R. Patton
Executive Vice President - External Affairs
Age 59
Executive Vice President - External Affairs since January 2017. President and Chief Operating Officer of APCo from June 2010 to December 2016.

Brian X. Tierney
Executive Vice President and Chief Financial Officer
Age 51
Executive Vice President and Chief Financial Officer since October 2009.

Charles E. Zebula
Executive Vice President - Energy Supply
Age 58
Executive Vice President - Energy Supply since January 2013.

ITEM 1A. RISK FACTORS

GENERAL RISKS OF REGULATED OPERATIONS

AEP may not be able to recover the costs of substantial planned investment in capital improvements and additions. (Applies to all Registrants)

AEP's business plan calls for extensive investment in capital improvements and additions, including the installation of environmental upgrades and retrofits, construction of additional transmission facilities, modernizing existing infrastructure as well as other initiatives. AEP's public utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. If these regulatory commissions do not approve adjustments to the rates charged, affected AEP subsidiaries would not be able to recover the costs associated with their investments. This would cause financial results to be diminished.

Regulated electric revenues and earnings are dependent on federal and state regulation that may limit AEP's ability to recover costs and other amounts. (Applies to all Registrants)

The rates customers pay to AEP regulated utility businesses are subject to approval by the FERC and the respective state utility commissions of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. In certain instances, AEP's applicable regulated utility businesses may agree to negotiated settlements related to various rate matters that are subject to regulatory approval. AEP cannot predict the ultimate outcomes of any settlements or the actions by the FERC or the respective state commissions in establishing rates.

If regulated utility earnings exceed the returns established by the relevant commissions, retail electric rates may be subject to review and possible reduction by the commissions, which may decrease future earnings. Additionally, if regulatory bodies do not allow recovery of costs incurred in providing service on a timely basis, it could reduce future net income and cash flows and negatively impact financial condition. Similarly, if recovery or other rate relief authorized in the past is overturned or reversed on appeal, future earnings could be negatively impacted. Any regulatory action or litigation outcome that triggers a reversal of a regulatory asset or deferred cost generally results in an impairment to the balance sheet and a charge to the income statement of the company involved. See Note 4 – Rate Matters included in the 2018 Annual Report for additional information.

AEP's transmission investment strategy and execution are dependent on federal and state regulatory policy. (Applies to all Registrants)

A significant portion of AEP's earnings is derived from transmission investments and activities. FERC policy currently favors the expansion and updating of the transmission infrastructure within its jurisdiction. If the FERC were to adopt a different policy, if states were to limit or restrict such policies, or if transmission needs do not continue or develop as projected, AEP's strategy of investing in transmission could be impacted. Management believes AEP's experience with transmission facilities construction and operation gives AEP an advantage over other competitors in securing authorization to install, construct and operate new transmission lines and facilities. However, there can be no assurance that PJM, SPP, ERCOT or other RTOs will authorize new transmission projects or will award such projects to AEP.

Certain elements of AEP's transmission formula rates have been challenged, which could result in lowered rates and/or refunds of amounts previously collected and thus have an adverse effect on AEP's business, financial condition, results of operations and cash flows. (Applies to all Registrants other than AEP Texas)

AEP provides transmission service under rates regulated by the FERC. The FERC has approved the cost-based formula rate templates used by AEP to calculate its respective annual revenue requirements, but it has not expressly approved the amount of actual capital and operating expenditures to be used in the formula rates. All aspects of AEP's rates accepted or approved by the FERC, including the formula rate templates, the rates of return on the actual equity portion of its respective capital structures and the approved targeted capital structures, are subject to challenge by interested parties at the FERC, or by the FERC on its own initiative. In addition, interested parties may challenge the annual

implementation and calculation by AEP of its projected rates and formula rate true up pursuant to its approved formula rate templates under AEP's formula rate implementation protocols. If a challenger can establish that any of these aspects are unjust, unreasonable, unduly discriminatory or preferential, then the FERC will make appropriate prospective adjustments to them and/or disallow any of AEP's inclusion of those aspects in the rate setting formula.

Parties have challenged AEP's formula rates in proceedings at the FERC. If the FERC orders revenue reductions as a result of these or other complaints, including refunds from the date of any complaint filing, it could reduce future net income and cash flows and impact financial condition.

End-use consumers and entities supplying electricity to end-use consumers may also attempt to influence government and/or regulators to change the rate setting methodologies that apply to AEP, particularly if rates for delivered electricity increase substantially.

Changes in technology and regulatory policies may lower the value of electric utility facilities and franchises. (Applies to all Registrants)

AEP primarily generates electricity at large central facilities and delivers that electricity to customers over its transmission and distribution facilities to customers usually situated within an exclusive franchise. This method results in economies of scale and generally lower costs than newer technologies such as fuel cells and microturbines, and distributed generation using either new or existing technology. Other technologies, such as light emitting diodes (LEDs), increase the efficiency of electricity and, as a result, lower the demand for it. Changes in regulatory policies and advances in batteries or energy storage, wind turbines and photovoltaic solar cells are reducing costs of new technology to levels that are making them competitive with some central station electricity production and delivery. These developments can challenge AEP's competitive ability to maintain relatively low cost, efficient and reliable operations, to establish fair regulatory mechanisms and to provide cost-effective programs and services to customers. Further, in the event that alternative generation resources are mandated, subsidized or encouraged through legislation or regulation or otherwise are economically competitive and added to the available generation supply, such resources could displace a higher marginal cost generating units, which could reduce the price at which market participants sell their electricity.

AEP may not recover costs incurred to begin construction on projects that are canceled. (Applies to all Registrants)

AEP's business plan for the construction of new projects involves a number of risks, including construction delays, nonperformance by equipment and other third-party suppliers, and increases in equipment and labor costs. To limit the risks of these construction projects, AEP's subsidiaries enter into equipment purchase orders and construction contracts and incur engineering and design service costs in advance of receiving necessary regulatory approvals and/or siting or environmental permits. If any of these projects are canceled for any reason, including failure to receive necessary regulatory approvals and/or siting or environmental permits, significant cancellation penalties under the equipment purchase orders and construction contracts could occur. In addition, if any construction work or investments have been recorded as an asset, an impairment may need to be recorded in the event the project is canceled.

AEP is exposed to nuclear generation risk. (Applies to AEP and I&M)

I&M owns the Cook Plant, which consists of two nuclear generating units for a rated capacity of 2,278 MWs, or about 7% of the generating capacity in the AEP System. AEP and I&M are, therefore, subject to the risks of nuclear generation, which include the following:

- The potential harmful effects on the environment and human health due to an adverse incident/event resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials such as SNF.
- Limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations.

- Uncertainties with respect to contingencies and assessment amounts triggered by a loss event (federal law requires owners of nuclear units to purchase the maximum available amount of nuclear liability insurance and potentially contribute to the coverage for losses of others).
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

There can be no assurance that I&M's preparations or risk mitigation measures will be adequate if these risks are triggered.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate substantial capital expenditures at nuclear plants. In addition, although management has no reason to anticipate a serious nuclear incident at the Cook Plant, if an incident did occur, it could harm results of operations or financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit. Moreover, a major incident at any nuclear facility in the U.S. could require AEP or I&M to make material contributory payments.

Costs associated with the operation (including fuel), maintenance and retirement of nuclear plants continue to be more significant and less predictable than costs associated with other sources of generation, in large part due to changing regulatory requirements and safety standards, availability of nuclear waste disposal facilities and experience gained in the operation of nuclear facilities. Costs also may include replacement power, any unamortized investment at the end of the useful life of the Cook Plant (whether scheduled or premature), the carrying costs of that investment and retirement costs. The ability to obtain adequate and timely recovery of costs associated with the Cook Plant is not assured.

AEP subsidiaries are exposed to risks through participation in the market and transmission structures in various regional power markets that are beyond their control. (Applies to all Registrants)

Results are likely to be affected by differences in the market and transmission structures in various regional power markets. The rules governing the various RTOs, including SPP and PJM, may also change from time to time which could affect costs or revenues. Existing, new or changed rules of these RTOs could result in significant additional fees and increased costs to participate in those structures, including the cost of transmission facilities built by others due to changes in transmission rate design. In addition, these RTOs may assess costs resulting from improved transmission reliability, reduced transmission congestion and firm transmission rights. As members of these RTOs, AEP's subsidiaries are subject to certain additional risks, including the allocation among existing members, of losses caused by unreimbursed defaults of other participants in these markets and resolution of complaint cases that may seek refunds of revenues previously earned by members of these markets.

AEP could be subject to higher costs and/or penalties related to mandatory reliability standards. (Applies to all Registrants)

Owners and operators of the bulk power transmission system are subject to mandatory reliability standards promulgated by the North American Electric Reliability Corporation and enforced by the FERC. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with new reliability standards may subject AEP to higher operating costs and/or increased capital expenditures. While management expects to recover costs and expenditures from customers through regulated rates, there can be no assurance that the applicable commissions will approve full recovery in a timely manner. If AEP were found not to be in compliance with the mandatory reliability standards, AEP could be subject to sanctions, including substantial monetary penalties, which likely would not be recoverable from customers through regulated rates.

A substantial portion of the receivables of AEP Texas is concentrated in a small number of REPs, and any delay or default in payment could adversely affect its cash flows, financial condition and results of operations. (Applies to AEP and AEP Texas)

AEP Texas collects receivables from the distribution of electricity from REPs that supply the electricity it distributes to its customers. As of December 31, 2018, AEP Texas did business with approximately 124 REPs. Adverse economic conditions, structural problems in the market served by ERCOT or financial difficulties of one or more REPs could impair the ability of these REPs to pay for these services or could cause them to delay such payments. AEP Texas depends on these REPs to remit payments on a timely basis. Applicable regulatory provisions require that customers be shifted to another REP or a provider of last resort if a REP cannot make timely payments. Applicable PUCT regulations significantly limit the extent to which AEP Texas can apply normal commercial terms or otherwise seek credit protection from firms desiring to provide retail electric service in its service territory, and AEP Texas thus remains at risk for payments related to services provided prior to the shift to another REP or the provider of last resort. In 2018, AEP Texas' first, second and third largest REPs accounted for 19%, 15% and 11%, respectively, of its operating revenue. Any delay or default in payment by REPs could adversely affect cash flows, financial condition and results of operations. If a REP were unable to meet its obligations, it could consider, among various options, restructuring under the bankruptcy laws, in which event such REP might seek to avoid honoring its obligations, and claims might be made by creditors involving payments AEP Texas had received from such REP.

RISKS RELATED TO MARKET, ECONOMIC OR FINANCIAL VOLATILITY AND OTHER RISKS

AEP's financial performance may be adversely affected if AEP is unable to successfully operate facilities or perform certain corporate functions. (Applies to all Registrants)

Performance is highly dependent on the successful operation of generation, transmission and/or distribution facilities. Operating these facilities involves many risks, including:

- Operator error and breakdown or failure of equipment or processes.
- Operating limitations that may be imposed by environmental or other regulatory requirements.
- Labor disputes.
- Compliance with mandatory reliability standards, including mandatory cyber security standards.
- Information technology failure that impairs AEP's information technology infrastructure or disrupts normal business operations.
- Information technology failure that affects AEP's ability to access customer information or causes loss of confidential or proprietary data that materially and adversely affects AEP's reputation or exposes AEP to legal claims.
- Fuel or water supply interruptions caused by transportation constraints, adverse weather such as drought, non-performance by suppliers and other factors.
- Catastrophic events such as fires, earthquakes, explosions, hurricanes, tornados, ice storms, terrorism (including cyber-terrorism), floods or other similar occurrences.
- Fuel costs and related requirements triggered by financial stress in the coal industry.

Physical attacks or hostile cyber intrusions could severely impair operations, lead to the disclosure of confidential information and damage AEP's reputation. (Applies to all Registrants)

AEP and its regulated utility businesses face physical security and cybersecurity risks as the owner-operators of generation, transmission and/or distribution facilities and as participants in commodities trading. AEP and its regulated utility businesses own assets deemed as critical infrastructure, the operation of which is dependent on information technology systems. Further, the computer systems that run these facilities are not completely isolated from external networks. Parties that wish to disrupt the U.S. bulk power system or AEP operations could view these computer systems, software or networks as targets for cyber attack. In addition, the electric utility business requires the collection of sensitive customer data, as well as confidential employee and shareholder information, which is subject to electronic theft or loss.

A security breach of AEP or its regulated utility businesses' physical assets or information systems, interconnected entities in RTOs, or regulators could impact the operation of the generation fleet and/or reliability of the transmission and distribution system or subject AEP and its regulated utility businesses to financial harm associated with theft or inappropriate release of certain types of information, including sensitive customer, vendor, employee, trading or other confidential data. A successful cyber attack on the systems that control generation, transmission, distribution or other assets could severely disrupt business operations, preventing service to customers or collection of revenues. The breach of certain business systems could affect the ability to correctly record, process and report financial information. A major cyber incident could result in significant expenses to investigate and repair security breaches or system damage and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to AEP's reputation. In addition, the misappropriation, corruption or loss of personally identifiable information and other confidential data could lead to significant breach notification expenses and mitigation expenses such as credit monitoring. For these reasons, a significant cyber incident could reduce future net income and cash flows and negatively impact financial condition.

If AEP is unable to access capital markets on reasonable terms, it could reduce future net income and cash flows and negatively impact financial condition. (Applies to all Registrants)

AEP relies on access to capital markets as a significant source of liquidity for capital requirements not satisfied by operating cash flows. Volatility, increased interest rates and reduced liquidity in the financial markets could affect AEP's ability to raise capital on reasonable terms to fund capital needs, including construction costs and refinancing maturing indebtedness. Certain sources of debt and equity capital expressed increasing unwillingness to invest in companies, such as AEP, that rely on fossil fuels. If sources of capital for AEP are reduced, capital costs could increase materially. Restricted access to capital markets and/or increased borrowing costs could reduce future net income and cash flows and negatively impact financial condition.

The potential phasing out of LIBOR after 2021 may adversely affect the costs and availability of financing. (Applies to all Registrants)

A portion of the Registrants' indebtedness bears interest at fluctuating interest rates, primarily based on the London interbank offered rate ("LIBOR") for deposits of U.S. dollars. LIBOR tends to fluctuate based on general interest rates, rates set by the U.S. Federal Reserve and other central banks, the supply of and demand for credit in the London interbank market and general economic conditions. AEP has not hedged its interest rate exposure with respect to its floating rate debt. Accordingly, Registrants' interest expense for any particular period will fluctuate based on LIBOR and other variable interest rates. On July 27, 2017, the Financial Conduct Authority (the authority that regulates LIBOR) announced that it intends to stop compelling banks to submit rates for the calculation of LIBOR after 2021. It is unclear whether new methods of calculating LIBOR will be established such that it continues to exist after 2021. The U.S. Federal Reserve, in conjunction with the Alternative Reference Rates Committee, is considering replacing U.S. dollar LIBOR with a newly created index, calculated based on repurchase agreements backed by treasury securities. It is not possible to predict the effect of these changes, other reforms or the establishment of alternative reference rates in the United Kingdom, the United States or elsewhere. To the extent these interest rates increase, interest expense will increase. If sources of capital for the Registrants are reduced, capital costs could increase materially. Restricted access to capital markets and/or increased borrowing costs could reduce future net income and cash flows and negatively impact financial condition and/or liquidity.

Downgrades in AEP's credit ratings could negatively affect its ability to access capital. (Applies to all Registrants)

The credit ratings agencies periodically review AEP's capital structure and the quality and stability of earnings and cash flows. Any negative ratings actions could constrain the capital available to AEP and could limit access to funding for operations. AEP's business is capital intensive, and AEP is dependent upon the ability to access capital at rates and on terms management determines to be attractive. If AEP's ability to access capital becomes significantly constrained, AEP's interest costs will likely increase and could reduce future net income and cash flows and negatively impact financial condition.

AEP has no income or cash flow apart from dividends paid or other payments due from its subsidiaries. (Applies to AEP)

AEP is a holding company and has no operations of its own. Its ability to meet its financial obligations associated with its indebtedness and to pay dividends on its common stock is primarily dependent on the earnings and cash flows of its operating subsidiaries, primarily its regulated utilities, and the ability of its subsidiaries to pay dividends to, or repay loans from, AEP. Its subsidiaries are separate and distinct legal entities that have no obligation (apart from loans from AEP) to provide AEP with funds for its payment obligations, whether by dividends, distributions or other payments. Payments to AEP by its subsidiaries are also contingent upon their earnings and business considerations. AEP indebtedness and common stock dividends are structurally subordinated to all subsidiary indebtedness.

AEP's operating results may fluctuate on a seasonal or quarterly basis and with general economic and weather conditions. (Applies to all Registrants)

Electric power consumption is generally seasonal. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. As a result, overall operating results in the future may fluctuate substantially on a seasonal basis. In addition, AEP has historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could reduce future net income and cash flows and negatively impact financial condition. In addition, unusually extreme weather conditions could impact AEP's results of operations in a manner that would not likely be sustainable.

Further, deteriorating economic conditions generally result in reduced consumption by customers, particularly industrial customers who may curtail operations or cease production entirely, while an expanding economic environment generally results in increased revenues. As a result, prevailing economic conditions may reduce future net income and cash flows and negatively impact financial condition.

Volatility in the securities markets, interest rates, and other factors could substantially increase defined benefit pension and other postretirement plan costs and the costs of nuclear decommissioning. (Applies to all Registrants and to AEP and I&M with respect to the costs of nuclear decommissioning)

The costs of providing pension and other postretirement benefit plans are dependent on a number of factors, such as the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plan, changes in actuarial assumptions, future government regulation, changes in life expectancy, and the frequency and amount of AEP's required or voluntary contributions made to the plans. Changes in actuarial assumptions and differences between the assumptions and actual values, as well as a significant decline in the value of investments that fund the pension and other postretirement plans, if not offset or mitigated by a decline in plan liabilities, could increase pension and other postretirement expense, and AEP could be required from time to time to fund the pension plan with significant amounts of cash. Such cash funding obligations could have a material impact on liquidity by reducing cash flows and could negatively affect results of operations.

Additionally, I&M holds a significant amount of assets in its nuclear decommissioning trusts to satisfy obligations to decommission its nuclear plant. The rate of return on assets held in those trusts can significantly impact both the costs of decommissioning and the funding requirements for the trusts.

AEP's results of operations and cash flows may be negatively affected by a lack of growth or slower growth in the number of customers, or decline in customer demand. (Applies to all Registrants)

Growth in customer accounts and growth of customer usage each directly influence demand for electricity and the need for additional power generation and delivery facilities. Customer growth and customer usage are affected by a number of factors outside the control of AEP, such as mandated energy efficiency measures, demand-side management goals, distributed generation resources and economic and demographic conditions, such as population changes, job and income growth, housing starts, new business formation and the overall level of economic activity.

Certain regulatory and legislative bodies have introduced or are considering requirements and/or incentives to further reduce energy consumption. Additionally, technological advances or other improvements in or applications of technology could lead to declines in per capita energy consumption. Some or all of these factors, could impact the demand for electricity.

Failure to attract and retain an appropriately qualified workforce could harm results of operations. (Applies to all Registrants)

Certain events, such as an aging workforce without appropriate replacements, mismatch of skillset or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect the ability to manage and operate the business. If AEP is unable to successfully attract and retain an appropriately qualified workforce, future net income and cash flows may be reduced.

Changes in the price of commodities, emission allowances for criteria pollutants and the costs of transport may increase AEP's cost of producing power, impacting financial performance. (Applies to all Registrants except AEP Texas, AEPTCo and OPCo)

AEP is exposed to changes in the price and availability of fuel (including coal and gas) and the price and availability to transport fuel. AEP has existing contracts of varying durations for the supply of fuel, but as these contracts end or if they are not honored, AEP may not be able to purchase fuel on terms as favorable as the current contracts. Similarly, AEP is exposed to changes in the price and availability of emission allowances. AEP uses emission allowances based on the amount of fuel used and reductions achieved through emission controls and other measures. Based on current environmental programs remaining in effect, AEP has sufficient emission allowances to cover the majority of the projected needs for the next two years and beyond. If the Federal EPA attempts to further reduce interstate transport, and it is acceptable by the courts, additional costs may be incurred either to acquire additional allowances or to achieve further reductions in emissions. If AEP needs to obtain allowances, those purchases may not be on as favorable terms as those under the current environmental programs. AEP's risks relative to the price and availability to transport coal include the volatility of the price of diesel which is the primary fuel used in transporting coal by barge.

Prices for coal, natural gas and emission allowances have shown material swings in the past. Changes in the cost of fuel, emission allowances or natural gas and changes in the relationship between such costs and the market prices of power could reduce future net income and cash flows and negatively impact financial condition.

In addition, actual power prices and fuel costs will differ from those assumed in financial projections used to value trading and marketing transactions, and those differences may be material. As a result, as those transactions are marked to market, they may impact future results of operations and cash flows and impact financial condition.

AEP is subject to physical and financial risks associated with climate change. (Applies to all Registrants)

Climate change creates physical and financial risk. Physical risks from climate change may include an increase in sea level and changes in weather conditions, such as changes in precipitation and extreme weather events, such as fires. Customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes.

Increased energy use due to weather changes may require AEP to invest in additional generating assets, transmission and other infrastructure to serve increased load. Decreased energy use due to weather changes may affect financial condition through decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stress, including service interruptions. Weather conditions outside of the AEP service territory could also have an impact on revenues. AEP buys and sells electricity depending upon system needs and market opportunities. Extreme weather conditions creating high energy demand on AEP's own and/or other systems may raise electricity prices as AEP buys short-term energy to serve AEP's own system, which would increase the cost of energy AEP provides to customers.

Severe weather and weather-related events impact AEP's service territories, primarily when thunderstorms, tornadoes, hurricanes, fires, floods and snow or ice storms occur. To the extent the frequency and intensity of extreme weather events and storms increase, AEP's cost of providing service will increase, and these costs may not be recoverable. Changes in precipitation resulting in droughts, water shortages or floods could adversely affect operations, principally the fossil fuel generating units. A negative impact to water supplies due to long-term drought conditions or severe flooding could adversely impact AEP's ability to provide electricity to customers, as well as increase the price they pay for energy. AEP may not recover all costs related to mitigating these physical and financial risks.

To the extent climate change impacts a region's economic health, it may also impact revenues. AEP's financial performance is tied to the health of the regional economies AEP serves. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods and services, has an impact on the economic health of the communities within the AEP System.

Management cannot predict the outcome of the legal proceedings relating to AEP's business activities. (Applies to all Registrants)

AEP is involved in legal proceedings, claims and litigation arising out of its business operations, the most significant of which are summarized in Note 6 - Commitments, Guarantees and Contingencies included in the 2018 Annual Report. Adverse outcomes in these proceedings could require significant expenditures that could reduce future net income and cash flows and negatively impact financial condition.

Disruptions at power generation facilities owned by third-parties could interrupt the sales of transmission and distribution services. (Applies to AEP and AEP Texas)

AEP Texas transmits and distributes electric power that the REPs obtain from power generation facilities owned by third-parties. If power generation is disrupted or if power generation capacity is inadequate, sales of transmission and distribution services may be diminished or interrupted, and results of operations, financial condition and cash flows could be adversely affected.

Hazards associated with high-voltage electricity transmission may result in suspension of AEP's operations or the imposition of civil or criminal penalties. (Applies to all Registrants)

AEP operations are subject to the usual hazards associated with high-voltage electricity transmission, including explosions, fires, inclement weather, natural disasters, mechanical failure, unscheduled downtime, equipment interruptions, remediation, chemical spills, discharges or releases of toxic or hazardous substances or gases and other environmental risks. The hazards can cause personal injury and loss of life, severe damage to or destruction of property and equipment and environmental damage, and may result in suspension of operations and the imposition of civil or criminal penalties. AEP maintains property and casualty insurance, but AEP is not fully insured against all potential hazards incident to AEP's business, such as damage to poles, towers and lines or losses caused by outages.

AEPTCo depends on its affiliates in the AEP System for a substantial portion of its revenues. (Applies to AEPTCo)

AEPTCo's principal transmission service customers are its affiliates in the AEP System. Management expects that these affiliates will continue to be AEPTCo's principal transmission service customers for the foreseeable future. For the year ended December 31, 2018, its affiliates were responsible for approximately 77% of the consolidated transmission revenues of AEPTCo.

Most of the real property rights on which the assets of AEPTCo are situated result from affiliate license agreements and are dependent on the terms of the underlying easements and other rights of its affiliates. (Applies to AEPTCo)

AEPTCo does not hold title to the majority of real property on which its electric transmission assets are located. Instead, under the provisions of certain affiliate contracts, it is permitted to occupy and maintain its facilities upon real property held by the respective AEP System utility affiliate that overlay its operations. The ability of AEPTCo to continue to occupy such real property is dependent upon the terms of such affiliate contracts and upon the underlying real property rights of these utility affiliates, which may be encumbered by easements, mineral rights and other similar encumbrances that may affect the use of such real property. AEP can give no assurance that (a) the relevant AEP System utility affiliates will continue to be affiliates of AEPTCo, (b) suitable replacement arrangements can be obtained in the event that the relevant AEP System utility affiliates are not its affiliates and (c) the underlying easements and other rights are sufficient to permit AEPTCo to operate its assets in a manner free from interruption.

RISKS RELATED TO OWNING AND OPERATING GENERATION ASSETS AND SELLING POWER

Costs of compliance with existing environmental laws are significant. (Applies to all Registrants except AEP Texas, AEPTCo and OPCo)

Operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and health and safety. A majority of the electricity generated by the AEP System is produced by the combustion of fossil fuels. Emissions of nitrogen and sulfur oxides, mercury and particulates from fossil fueled generation plants are subject to increased regulations, controls and mitigation expenses. Compliance with these legal requirements requires AEP to commit significant capital toward environmental monitoring, installation of pollution control equipment, emission fees and permits at all AEP facilities and could cause AEP to retire generating capacity prior to the end of its estimated useful life. Costs of compliance with environmental regulations could reduce future net income and negatively impact financial condition, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed or additional substances become regulated. Although AEP typically recovers expenditures for pollution control technologies, replacement generation, undepreciated plant balances and associated operating costs from customers, there can be no assurance that AEP will recover the remaining costs associated with such plants. Failure to recover these costs could reduce future net income and cash flows and possibly harm financial condition.

Regulation of CO_2 emissions could materially increase costs to AEP and its customers or cause some electric generating units to be uneconomical to operate or maintain. (Applies to all Registrants except AEP Texas, AEPTCo and OPCo)

In 2014, the Federal EPA issued standards for new, modified and reconstructed units, and a guideline for the development of SIPs that would reduce carbon emissions from existing utility units. The standards and guidelines were finalized in 2015, and have been challenged by several dozen states as well as industry groups and other stakeholders. The U.S. Supreme Court has stayed the implementation of the guidelines for existing sources, known as the Clean Power Plan, until a final decision is issued by the courts. In 2017, the Federal EPA issued a proposal to repeal the Clean Power Plan, and an advance notice of proposed rulemaking seeking information that should be considered in the development of new emission guidelines. In 2018, the Federal EPA issued proposed guidelines that would allow states to establish unit-specific performance standards based on their evaluation of past performance and whether certain efficiency improvement measures could be applied at existing coal-fired units. The Federal EPA also proposed to change the new source performance standard for new coal-fired utility units to 1,900 - 2,000 pounds per MWh depending on the size of the unit, an increase from the current standard of 1,400 pounds per MWh, based on its determination that carbon capture and storage is not available everywhere and is not sufficiently cost-effective to be considered the best available control technology for coal-fired units.

CO_2 standards could require significant increases in capital expenditures and operating costs and could impact the dates for retirement of AEP's coal-fired units. While AEP typically recovers costs of complying with new requirements, such as the potential CO_2 and other greenhouse gases emission standards from customers, there can be no assurance that AEP would recover such costs.

Courts adjudicating nuisance and other similar claims in the future may order AEP to pay damages or to limit or reduce emissions. (Applies to all Registrants except AEP Texas, AEPTCo and OPCo)

In the past, there have been several cases seeking damages based on allegations of federal and state common law nuisance in which AEP, among others, were defendants. In general, the actions allege that emissions from the defendants' power plants constitute a public nuisance. The plaintiffs in these actions generally seek recovery of damages and other relief. If future actions are resolved against AEP, substantial modifications of AEP's existing coal-fired power plants could be required and AEP might be required to limit or reduce emissions. Such remedies could require AEP to purchase power from third-parties to fulfill AEP's commitments to supply power to AEP customers. This could have a material impact on costs. In addition, AEP could be required to invest significantly in additional emission control equipment, accelerate the timing of capital expenditures, pay damages or penalties and/or halt operations. Unless recovered, those costs could reduce future net income and cash flows and harm financial condition. Moreover, results of operations and financial position could be reduced due to the timing of recovery of these investments and the expense of ongoing litigation.

Commodity trading and marketing activities are subject to inherent risks which can be reduced and controlled but not eliminated. (Applies to all Registrants except AEP Texas, AEPTCo and OPCo)

AEP routinely has open trading positions in the market, within guidelines set by AEP, resulting from the management of AEP's trading portfolio. To the extent open trading positions exist, fluctuating commodity prices can improve or diminish financial results and financial position.

AEP's power trading activities also expose AEP to risks of commodity price movements. To the extent that AEP's power trading does not hedge the price risk associated with the generation it owns, or controls, AEP would be exposed to the risk of rising and falling spot market prices.

In connection with these trading activities, AEP routinely enters into financial contracts, including futures and options, OTC options, financially-settled swaps and other derivative contracts. These activities expose AEP to risks from price movements. If the values of the financial contracts change in a manner AEP does not anticipate, it could harm financial position or reduce the financial contribution of trading operations.

Parties with whom AEP has contracts may fail to perform their obligations, which could harm AEP's results of operations. (Applies to all Registrants)

AEP sells power from its generation facilities into the spot market and other competitive power markets on a contractual basis. AEP also enters into contracts to purchase and sell electricity, natural gas, emission allowances and coal as part of its power marketing and energy trading operations. AEP is exposed to the risk that counterparties that owe AEP money or the delivery of a commodity, including power, could breach their obligations. Should the counterparties to these arrangements fail to perform, AEP may be forced to enter into alternative hedging arrangements or honor underlying commitments at then-current market prices that may exceed AEP's contractual prices, which would cause financial results to be diminished and AEP might incur losses. Although estimates take into account the expected probability of default by a counterparty, actual exposure to a default by a counterparty may be greater than the estimates predict.

AEP relies on electric transmission facilities that AEP does not own or control. If these facilities do not provide AEP with adequate transmission capacity, AEP may not be able to deliver wholesale electric power to the purchasers of AEP's power. (Applies to all Registrants)

AEP depends on transmission facilities owned and operated by other nonaffiliated power companies to deliver the power AEP sells at wholesale. This dependence exposes AEP to a variety of risks. If transmission is disrupted, or transmission capacity is inadequate, AEP may not be able to sell and deliver AEP wholesale power. If a region's power transmission infrastructure is inadequate, AEP's recovery of wholesale costs and profits may be limited. If restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in expansion of transmission infrastructure.

The FERC has issued electric transmission initiatives that require electric transmission services to be offered unbundled from commodity sales. Although these initiatives are designed to encourage wholesale market transactions, access to transmission systems may not be available if transmission capacity is insufficient because of physical constraints or because it is contractually unavailable. Management also cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets.

OVEC may require additional liquidity and other capital support. (Applies to AEP, APCo, I&M and OPCo)

AEP and several nonaffiliated utility companies own OVEC. The Inter-Company Power Agreement (ICPA) defines the rights and obligations and sets the power participation ratio of the parties to it. Under the ICPA, parties are entitled to receive and are obligated to pay for all OVEC capacity (approximately 2,400 MWs) in proportion to their respective power participation ratios. The aggregate power participation ratio of APCo, I&M and OPCo is 43.47%. If a party fails to make payments owed by it under the ICPA, OVEC may not have sufficient funds to honor its payment obligations, including its ongoing operating expenses as well as its indebtedness. As of December 31, 2018, OVEC has outstanding indebtedness of approximately \$1.4 billion, of which APCo, I&M, and OPCo are collectively responsible for \$604 million through the ICPA. Although they are not an obligor or guarantor, APCo, I&M, and OPCo are responsible for their respective ratio of OVEC's outstanding debt through the ICPA.

FirstEnergy Solutions ("FES"), a nonaffiliated party, whose aggregate power participation ratio is 4.85% under the ICPA, has filed a petition seeking protection under bankruptcy law. The bankruptcy court has granted the motion of FES to reject the ICPA. Litigation related to these filings continues. In addition, as a result of these and prior related developments, OVEC's credit ratings have been adversely impacted.

If OVEC does not have sufficient funds to honor its payment obligations, there is risk that APCo, I&M and/or OPCo may need to make payments in addition to their power participation ratio payments. Further, if OVEC's indebtedness is accelerated for any reason, there is risk that APCo, I&M and/or OPCo may be required to pay some or all of such accelerated indebtedness in amounts equal to their aggregate power participation ratio of 43.47%. Also, as a result of the credit rating agencies' actions, OVEC's ability to access capital markets on terms as favorable as previously may diminish and its financing costs will increase.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

GENERATION FACILITIES

As of December 31, 2018 the AEP System owned (or leased where indicated) generation plants, with locations and net maximum power capabilities (winter rating), are shown in the following tables:

Vertically Integrated Utilities Segment

AEGCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Rockport, Units 1 and 2 – 50% of each (a)	2	IN	Steam - Coal	1,310	1984

(a) Rockport Plant, Unit 2 is leased.

AEP Texas

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Oklaunion Power Station (a) (b)	1	TX	Steam - Coal	355	1986

(a) Jointly-owned with PSO and nonaffiliated entities. Figures presented reflect only the portion owned by AEP Texas.
(b) In September 2018, management announced plans to close the plant by October 2020.

APCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Buck	3	VA	Hydro	11	1912
Byllesby	4	VA	Hydro	19	1912
Claytor	4	VA	Hydro	75	1939
Leesville	2	VA	Hydro	50	1964
London	3	WV	Hydro	14	1935
Marmet	3	WV	Hydro	14	1935
Niagara	2	VA	Hydro	2	1906
Winfield	3	WV	Hydro	15	1938
Ceredo	6	WV	Natural Gas	516	2001
Dresden	3	OH	Natural Gas	613	2012
Smith Mountain	5	VA	Pumped Storage	585	1965
Amos	3	WV	Steam - Coal	2,930	1971
Mountaineer	1	WV	Steam - Coal	1,320	1980
Clinch River	2	VA	Steam - Natural Gas	465	1958
Total MWs				6,629	

I&M

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Berrien Springs	12	MI	Hydro	6	1908
Buchanan	10	MI	Hydro	3	1919
Constantine	4	MI	Hydro	1	1921
Elkhart	3	IN	Hydro	3	1913
Mottville	4	MI	Hydro	2	1923
Twin Branch Hydro	8	IN	Hydro	5	1904
Deer Creek Solar Farm	NA	IN	Solar	3	2016
Olive Solar Farm	NA	IN	Solar	5	2016
Twin Branch Solar Farm	NA	IN	Solar	3	2016
Watervliet	NA	MI	Solar	5	2016
Rockport (Units 1 and 2, 50% of each) (a)	2	IN	Steam - Coal	1,310	1984
Cook	2	MI	Steam - Nuclear	2,278	1975
Total MWs				3,624	

NA Not applicable.
(a) Rockport Plant, Unit 2 is leased.

The following table provides operating information related to the Cook Plant:

	Cook Plant	
	Unit 1	Unit 2
Year Placed in Operation	1975	1978
Year of Expiration of NRC License	2034	2037
Nominal Net Electrical Rating in MWs	1,084	1,194
Annual Capacity Utilization		
2018	97.9%	79.5%
2017	76.5%	98.8%
2016	87.3%	72.5%

KPCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Mitchell (a)	2	WV	Steam - Coal	780	1971
Big Sandy	1	KY	Steam - Natural Gas	280	1963
Total MWs				1,060	

(a) KPCo owns a 50% interest in the Mitchell Plant units. WPCo owns the remaining 50%. Figures presented reflect only the portion owned by KPCo.

PSO

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Comanche	3	OK	Natural Gas	248	1973
Riverside, Units 3 and 4	2	OK	Natural Gas	160	2008
Southwestern, Units 4 and 5	2	OK	Natural Gas	170	2008
Weleetka (a)	3	OK	Natural Gas	160	1975
Northeastern, Unit 1	1	OK	Natural Gas	470	1961
Northeastern, Unit 3	1	OK	Steam - Coal	469	1979
Oklaunion Power Station (b) (c)	1	TX	Steam - Coal	105	1986
Northeastern, Unit 2	1	OK	Steam - Natural Gas	434	1961
Riverside, Units 1 and 2	2	OK	Steam - Natural Gas	901	1974
Southwestern, Units 1, 2 and 3	3	OK	Steam - Natural Gas	451	1952
Tulsa	2	OK	Steam - Natural Gas	325	1956
Total MWs				3,893	

(a) Weleetka Unit 6 is scheduled for retirement in March 2019.
(b) Jointly-owned with AEP Texas and nonaffiliated entities. Figures presented reflect only the portion owned by PSO.
(c) In September 2018, management announced plans to close the plant by October 2020.

SWEPCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Mattison	4	AR	Natural Gas	315	2007
Stall	3	LA	Natural Gas	534	2010
Flint Creek (a)	1	AR	Steam - Coal	258	1978
Turk (a)	1	AR	Steam - Coal	477	2012
Welsh	2	TX	Steam - Coal	1,053	1977
Dolet Hills (a)	1	LA	Steam - Lignite	257	1986
Pirkey (a)	1	TX	Steam - Lignite	580	1985
Arsenal Hill	1	LA	Steam - Natural Gas	110	1960
Knox Lee (b)	4	TX	Steam - Natural Gas	475	1950
Lieberman	3	LA	Steam - Natural Gas	242	1947
Lone Star	1	TX	Steam - Natural Gas	50	1954
Wilkes	3	TX	Steam - Natural Gas	889	1964
Total MWs				5,240	

(a) Jointly-owned with nonaffiliated entities. Figures presented reflect only the portion owned by SWEPCo. The Arkansas jurisdictional portion of SWEPCo's interest in Turk Plant is not in rate base.
(b) Knox Lee Unit 4 was retired in January 2019. Figures presented include Unit 4 in the total.

WPCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Mitchell (a)	2	WV	Steam - Coal	780	1971

(a) 17.5% of WPCo's interest in the Mitchell Plant units is not in rate base. KPCo owns the remaining 50%. Figures presented reflect only the portion owned by WPCo.

Generation & Marketing Segment

AGR

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Racine	2	OH	Hydro	48	1982
Cardinal	1	OH	Steam - Coal	595	1967
Conesville (a) (b)	3	OH	Steam - Coal	1,471	1957
Total MWs				2,114	

(a) Jointly-owned with nonaffiliated entities. Figures presented reflect only the portion owned by AGR.
(b) In the fourth quarter of 2018, management announced plans to close Conesville Plant Units 5 and 6 in May 2019 and Unit 4 in May 2020.

Renewable Power

Size of Energy Resource	Renewable Energy Resource	Location	In-Service or Under Construction
261 MW	Wind	Texas	In service
20 MW	Solar	California	In service
20 MW	Solar	Utah	In service
50 MW	Solar	Nevada	In service
85 MW	Solar	Fifteen states (a)	In service
57 MW	Solar	Four states (b)	Under Construction

(a) California, Colorado, Connecticut, Florida, Hawaii, Minnesota, Nebraska, New Hampshire, New Jersey, New Mexico, New York, Ohio, Rhode Island, Texas and Vermont.
(b) Colorado, Minnesota, New Mexico and Hawaii.

In addition to the AGR and Renewable Power generation set forth above, a subsidiary in the Generation & Marketing segment has contractual rights through 2027 from AEP Texas to 355 MWs from the Oklaunion Power Station. AEP Texas co-owns the Oklaunion Power Station with PSO and several nonaffiliated entities. Management has announced plans to close Oklaunion Power Station by October 2020.

TRANSMISSION AND DISTRIBUTION FACILITIES

The following tables set forth the total overhead circuit miles of transmission and distribution lines of the AEP System and its operating companies.

Vertically Integrated Utilities Segment

	Total Overhead Circuit Miles of Transmission and Distribution Lines
APCo	51,632
I&M	21,453
KGPCo	1,405
KPCo	11,147
PSO	18,334
SWEPCo	26,093
WPCo	1,744
Total Circuit Miles	131,808

Transmission and Distribution Utilities Segment

	Total Overhead Circuit Miles of Transmission and Distribution Lines
OPCo	44,944
AEP Texas	45,838
Total Circuit Miles	90,782

AEP Transmission Holdco Segment

The following table sets forth the total overhead circuit miles of transmission lines of certain wholly-owned and joint venture-owned entities:

	Total Overhead Circuit Miles of Transmission Lines
ETT	1,774
IMTCo	425
OHTCo	749
OKTCo	720
WVTCo	188
Pioneer	43
Prairie Wind Transmission	216
Transource Missouri	167
Total Circuit Miles	4,282

TITLE TO PROPERTY

The AEP System's generating facilities are generally located on lands owned in fee simple. The greater portion of the transmission and distribution lines of the AEP System has been constructed over lands of private owners pursuant to easements or along public highways and streets pursuant to appropriate statutory authority. The rights of AEP's public utility subsidiaries in the realty on which their facilities are located are considered adequate for use in the conduct of their business. Minor defects and irregularities customarily found in title to properties of like size and character may exist, but such defects and irregularities do not materially impair the use of the properties. AEP's public utility subsidiaries generally have the right of eminent domain which permits them, if necessary, to acquire, perfect or secure titles to or easements on privately held lands used or to be used in their utility operations. Legislation in Ohio and Virginia has restricted the right of eminent domain previously granted for power generation purposes.

SYSTEM TRANSMISSION LINES AND FACILITY SITING

Laws in the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Tennessee, Texas, Virginia and West Virginia require prior approval of sites of generating facilities and/or routes of high-voltage transmission lines. AEP has experienced delays and additional costs in constructing facilities as a result of proceedings conducted pursuant to such statutes and in proceedings in which AEP's operating companies have sought to acquire rights-of-way through condemnation. These proceedings may result in additional delays and costs in future years.

CONSTRUCTION PROGRAM

With input from its state utility commissions, the AEP System continuously assesses the adequacy of its transmission, distribution, generation and other facilities to plan and provide for the reliable supply of electric power and energy to its customers. In this assessment process, assumptions are continually being reviewed as new information becomes available and assessments and plans are modified, as appropriate. AEP forecasts approximately $7.8 billion of construction expenditures for 2019. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather and the ability to access capital. See the "Budgeted Construction Expenditures" section of Management's Discussion and Analysis of Financial Condition and Results of Operations included in the 2018 Annual Report for additional information.

POTENTIAL UNINSURED LOSSES

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including liabilities relating to damage to AEP's generation plants and costs of replacement power. Unless allowed to be recovered through rates, future losses or liabilities which are not completely insured could reduce net income and impact the financial conditions of AEP and other AEP System companies. For risks related to owning a nuclear generating unit, see the "Nuclear Contingencies" section of Note 6 - Commitments, Guarantees and Contingencies included in the 2018 Annual Report for information with respect to nuclear incident liability insurance.

ITEM 3. LEGAL PROCEEDINGS

For a discussion of material legal proceedings, see Note 6 - Commitments, Guarantees and Contingencies included in the 2018 Annual Report, incorporated by reference in Item 8 and herein.

ITEM 4. MINE SAFETY DISCLOSURE

The Federal Mine Safety and Health Act of 1977 (Mine Act) imposes stringent health and safety standards on various mining operations. The Mine Act and its related regulations affect numerous aspects of mining operations, including training of mine personnel, mining procedures, equipment used in mine emergency procedures, mine plans and other matters. SWEPCo, through its ownership of Dolet Hills Lignite Company (DHLC), a wholly-owned lignite mining subsidiary of SWEPCo, is subject to the provisions of the Mine Act.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires companies that operate mines to include in their periodic reports filed with the SEC, certain mine safety information covered by the Mine Act. Exhibit 95 "Mine Safety Disclosure Exhibit" contains the notices of violation and proposed assessments received by DHLC under the Mine Act for the quarter ended December 31, 2018.

PART II

ITEM 5. MARKET FOR REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

AEP

In addition to the discussion below, the remaining information required by this item is incorporated herein by reference to the material under AEP Common Stock Information and "Management's Discussion and Analysis of Financial Condition and Results of Operations - Dividend Policy and Restrictions" included in the 2018 Annual Report.

AEP Texas, APCo, I&M, OPCo, PSO and SWEPCo

The common stock of these companies is held solely by AEP. For more information see the "Dividend Restrictions" section of Note 14 - Financing Activities included in the 2018 Annual Report.

AEPTCo

AEP owns the entire interest in AEPTCo through its wholly-owned subsidiary AEP Transmission Holdco.

During the quarter ended December 31, 2018, neither AEP nor its publicly-traded subsidiaries purchased equity securities that are registered by AEP or its publicly-traded subsidiaries pursuant to Section 12 of the Exchange Act.

ITEM 6. SELECTED FINANCIAL DATA

AEP

The information required by this item is incorporated herein by reference to the material under Selected Consolidated Financial Data in the 2018 Annual Report.

AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(a). Management's narrative analysis of the results of operations and other information required by Instruction I(2)(a) is incorporated herein by reference to the material under Management's Discussion and Analysis of Financial Condition and Results of Operations in the 2018 Annual Report.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

AEP

The information required by this item is incorporated herein by reference to the material under Management's Discussion and Analysis of Financial Condition and Results of Operations in the 2018 Annual Report.

AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(a). Management's narrative analysis of the results of operations and other information required by Instruction I(2)(a) is incorporated herein by reference to the material under Management's Discussion and Analysis of Financial Condition and Results of Operations in the 2018 Annual Report.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

The information required by this item is incorporated herein by reference to the material under the "Quantitative and Qualitative Disclosures About Market Risk" section of Management's Discussion and Analysis of Financial Condition and Results of Operations in the 2018 Annual Report.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

The information required by this item is incorporated herein by reference to the financial statements and financial statement schedules described under Item 15 herein.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Information required by this item is set forth under the caption Proposal to Ratify the Appointment of the Independent Registered Public Accounting Firm in the 2019 Proxy Statement, which is incorporated by reference into this item.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

During 2018, management, including the principal executive officer and principal financial officer of each of American Electric Power Company, Inc. ("AEP"), AEP Texas Inc., AEP Transmission Company, LLC, Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company (each a "Registrant" and collectively the "Registrants") evaluated each respective Registrant's disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrant that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the Commission's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to each Registrant's management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As of December 31, 2018, the principal executive officer and financial officer of each of the Registrants concluded that the disclosure controls and procedures in place were effective at the reasonable assurance level. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting and to maintain dynamic systems that change as events warrant.

Changes in Internal Control over Financial Reporting

There have been no changes in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth quarter 2018 that materially affected, or is reasonably likely to materially affect, the Registrants' internal control over financial reporting.

Internal Control over Financial Reporting

See Management's Report on Internal Control over Financial Reporting for each Registrant under Item 8. As discussed in that report, management assessed and reported on the effectiveness of each Registrant's internal control over financial reporting as of December 31, 2018. As a result of that assessment, management concluded that each Registrant's internal control over financial reporting was effective as of December 31, 2018.

ITEM 9B. OTHER INFORMATION

On February 18, 2019, the HR Committee of AEP's Board of Directors (the "HR Committee") made a special equity award grant to Brian X. Tierney, AEP's Chief Financial Officer and Lisa M. Barton, AEP's Executive Vice President-Utilities. The HR Committee awarded one-time restricted stock unit ("RSU") retention awards under the Company's Long-Term Incentive Plan (the "LTIP") to Mr. Tierney and Ms. Barton as part of a retention strategy. The retention awards were granted with the regular cycle LTIP awards in February 2019. The retention awards provided $2,000,000 in RSUs to each executive that will vest over a 40 month period, with 25% of the awards vesting on May 1, 2020, 37.5% of the awards vesting on May 1, 2021 and 37.5% of the awards vesting on May 1, 2022. The retention awards have no value to the executive unless he/she remains employed with the Company for the vesting period, and will be canceled if the executive's employment with the Company terminates.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

AEP

Directors, Director Nomination Process and Audit Committee

Certain of the information called for in this Item 10, including the information relating to directors, is incorporated herein by reference to AEP's definitive proxy information statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to the 2019 Annual Meeting of Shareholders (the 2019 Annual Meeting) including under the captions "Election of Directors," "Section 16(a) Beneficial Ownership Reporting Compliance," "AEP's Board of Directors and Committees," "Directors" and "Shareholder Nominees for Directors."

Executive Officers

Reference also is made to the information under the caption Executive Officers of AEP in Part I, Item 1 of this report.

Code of Ethics

AEP's Principles of Business Conduct is the code of ethics that applies to AEP's Chief Executive Officer, Chief Financial Officer and principal accounting officer. The Principles of Business Conduct is available on AEP's website at www.aep.com. The Principles of Business Conduct will be made available, without charge, in print to any shareholder who requests such document from Investor Relations, American Electric Power Company, Inc., 1 Riverside Plaza, Columbus, Ohio 43215.

If any substantive amendments to the Principles of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of the Principles of Business Conduct, to its Chief Executive Officer, Chief Financial Officer or principal accounting officer, AEP will disclose the nature of such amendment or waiver on AEP's website, www.aep.com, or in a report on Form 8-K.

Section 16(a) Beneficial Ownership Reporting Compliance

The information required by this item is incorporated herein by reference to information contained in the definitive proxy statement of AEP for the 2019 Annual Meeting.

AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(c).

ITEM 11. EXECUTIVE COMPENSATION

AEP

The information called for by this Item 11 is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to the 2019 Annual Meeting including under the captions "Compensation Discussion and Analysis," "Executive Compensation", "Director Compensation" and "2018 Director Compensation Table". The information set forth under the subcaption "Human Resources Committee Report" and "Audit Committee Report" should not be deemed filed nor should it be incorporated by reference into any other filing under the Securities Act of 1933, as amended, or the Exchange Act except to the extent AEP specifically incorporates such report by reference therein.

AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(c).

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

AEP

The information relating to Security Ownership of Certain Beneficial Owners is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to 2019 Annual Meeting under the caption "Share Ownership of Certain Beneficial Owners and Management" and "Share Ownership of Directors and Executive Officers."

EQUITY COMPENSATION PLAN INFORMATION

The following table summarizes the ability of AEP to issue common stock pursuant to equity compensation plans as of December 31, 2018:

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options Warrants and Rights (a)	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans
Equity Compensation Plans Approved by Security Holders	2,266,358	—	8,194,046
Equity Compensation Plans Not Approved by Security Holders	—	—	—
Total	2,266,358	—	8,194,046

(a) The balance includes unvested 2018 performance units and restricted stock units as well as vested performance units deferred as AEP career shares, all of which will be settled and paid in shares of AEP common stock. Performance units, restricted stock units and AEP career shares that are settled and paid in cash are not included. For performance units, the total includes the target number of shares that could be granted if performance meets target objectives. The number of securities that would be granted, with respect to performance units, if performance meets the maximum payout level, is two times the amount included in this total.

(b) No consideration is required from participants for the exercise or vesting of any outstanding AEP equity compensation awards.

AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(c).

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

AEP

The information called for by this Item 13 is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to the 2019 Annual Meeting under the captions "Transactions with Related Persons" and "Director Independence."

AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(c).

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

AEP

The information called for by this Item 14 is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to the 2019 Annual Meeting under the captions "Audit and Non-Audit Fees," "Audit Committee Report" and "Policy on Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of the Independent Auditor."

AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo

Each of the above is a wholly-owned subsidiary of AEP and does not have a separate audit committee. A description of the AEP Audit Committee pre-approval policies, which apply to these companies, is contained in the definitive proxy statement of AEP for the 2019 Annual Meeting of shareholders. The following table presents directly billed fees for professional services rendered by PricewaterhouseCoopers LLP for the audit of these companies' annual financial statements for the years ended December 31, 2018 and 2017, and fees directly billed for other services rendered by PricewaterhouseCoopers LLP during those periods. PricewaterhouseCoopers LLP also provides additional professional and other services to the AEP System, the cost of which may ultimately be allocated to these companies though not billed directly to them. For a description of these fees and services, see the description of principal accounting fees and services for AEP above.

	AEP Texas		AEPTCo		APCo	
	2018	2017	2018	2017	2018	2017
Audit Fees	$ 1,129,561	$ 1,081,882	$ 1,193,523	$ 947,509	$ 1,721,299	$ 1,756,776
Audit-Related Fees	76,000	76,000	—	—	42,571	45,738
Tax Fees	34,880	—	33,001	—	52,714	—
All Other Fees	13,247	—	12,534	—	40,530	—
Total	$ 1,253,688	$ 1,157,882	$ 1,239,058	$ 947,509	$ 1,857,114	$ 1,802,514

	I&M		OPCo		PSO	
	2018	2017	2018	2017	2018	2017
Audit Fees	$ 1,510,574	$ 1,503,971	$ 1,093,392	$ 1,042,136	$ 603,527	$ 654,569
Audit-Related Fees	10,071	7,738	48,071	45,738	4,571	7,738
Tax Fees	43,472	—	34,019	—	19,475	—
All Other Fees	24,715	—	12,920	—	21,415	—
Total	$ 1,588,832	$ 1,511,709	$ 1,188,402	$ 1,087,874	$ 648,988	$ 662,307

	SWEPCo	
	2018	2017
Audit Fees	$ 1,150,091	$ 1,071,925
Audit-Related Fees	24,571	55,738
Tax Fees	33,188	—
All Other Fees	29,131	—
Total	$ 1,236,981	$ 1,127,663

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

The following documents are filed as a part of this report:

1. FINANCIAL STATEMENTS:

The following financial statements have been incorporated herein by reference pursuant to Item 8.

AEP and Subsidiary Companies:

Report of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting; Consolidated Statements of Income for the years ended December 31, 2018, 2017 and 2016; Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2018, 2017 and 2016; Consolidated Statements of Changes in Equity for the years ended December 31, 2018, 2017 and 2016; Consolidated Balance Sheets as of December 31, 2018 and 2017; Consolidated Statements of Cash Flows for the years ended December 31, 2018, 2017 and 2016; Notes to Financial Statements of Registrants.

AEP Texas, APCo, I&M and OPCo:

Report of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting; Consolidated Statements of Income for the years ended December 31, 2018, 2017 and 2016; Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2018, 2017 and 2016; Consolidated Statements of Changes in Common Shareholder's Equity for the years ended December 31, 2018, 2017 and 2016; Consolidated Balance Sheets as of December 31, 2018 and 2017; Consolidated Statements of Cash Flows for the years ended December 31, 2018, 2017 and 2016; Notes to Financial Statements of Registrants.

AEPTCo:

Report of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting; Consolidated Statements of Income for the years ended December 31, 2018, 2017 and 2016; Consolidated Statements of Changes in Member's Equity for the years ended December 31, 2018, 2017 and 2016; Consolidated Balance Sheets as of December 31, 2018 and 2017; Consolidated Statements of Cash Flows for the years ended December 31, 2018, 2017 and 2016; Notes to Financial Statements of Registrants.

PSO:

Report of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting; Statements of Income for the years ended December 31, 2018, 2017 and 2016; Statements of Comprehensive Income (Loss) for the years ended December 31, 2018, 2017 and 2016; Statements of Changes in Common Shareholder's Equity for the years ended December 31, 2018, 2017 and 2016; Balance Sheets as of December 31, 2018 and 2017; Statements of Cash Flows for the years ended December 31, 2018, 2017 and 2016; Notes to Financial Statements of Registrants.

SWEPCo:

Report of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting; Consolidated Statements of Income for the years ended December 31, 2018, 2017 and 2016; Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2018, 2017 and 2016; Consolidated Statements of Changes in Equity for the years ended December 31, 2018, 2017 and 2016; Consolidated Balance Sheets as of December 31, 2018 and 2017; Consolidated Statements of Cash Flows for the years ended December 31, 2018, 2017 and 2016; Notes to Financial Statements of Registrants.

	Page Number
2. FINANCIAL STATEMENT SCHEDULES:	
Financial Statement Schedules are listed in the Index of Financial Statement Schedules. (Certain schedules have been omitted because the required information is contained in the notes to financial statements or because such schedules are not required or are not applicable). Reports of Independent Registered Public Accounting Firm.	S-1
3. EXHIBITS:	
Exhibits for AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo are listed in the Exhibit Index beginning on page E-1 and are incorporated herein by reference.	E-1

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

American Electric Power Company, Inc.

By: /s/ Brian X. Tierney
(Brian X. Tierney, Executive Vice President and Chief Financial Officer)

Date: February 21, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ Nicholas K. Akins **(Nicholas K. Akins)**	Chairman of the Board, Chief Executive Officer and Director	February 21, 2019
(ii) Principal Financial Officer:		
/s/ Brian X. Tierney **(Brian X. Tierney)**	Executive Vice President and Chief Financial Officer	February 21, 2019
(iii) Principal Accounting Officer:		
/s/ Joseph M. Buonaiuto **(Joseph M. Buonaiuto)**	Senior Vice President, Controller and Chief Accounting Officer	February 21, 2019
(iv) A Majority of the Directors:		
*Nicholas K. Akins *David J. Anderson *J. Barnie Beasley, Jr. *Ralph D. Crosby, Jr. *Linda A. Goodspeed *Thomas E. Hoaglin *Sandra Beach Lin *Richard C. Notebaert *Lionel L. Nowell, III *Stephen S. Rasmussen *Oliver G. Richard, III *Sara Martinez Tucker		
*By: /s/ Brian X. Tierney **(Brian X. Tierney, Attorney-in-Fact)**		February 21, 2019

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AEP Texas Inc.
Appalachian Power Company
Ohio Power Company
Public Service Company of Oklahoma
Southwestern Electric Power Company

By: /s/ Brian X. Tierney
(Brian X. Tierney, Vice President and Chief Financial Officer)

Date: February 21, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

	Signature	Title	Date
(i)	**Principal Executive Officer:**		
	/s/ Nicholas K. Akins **(Nicholas K. Akins)**	Chairman of the Board, Chief Executive Officer and Director	February 21, 2019
(ii)	**Principal Financial Officer:**		
	/s/ Brian X. Tierney **(Brian X. Tierney)**	Vice President, Chief Financial Officer and Director	February 21, 2019
(iii)	**Principal Accounting Officer:**		
	/s/ Joseph M. Buonaiuto **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	February 21, 2019
(iv)	**A Majority of the Directors:**		
	*Nicholas K. Akins *Lisa M. Barton *Paul Chodak III *David M. Feinberg *Lana L. Hillebrand *Mark C. McCullough		

*Charles R. Patton
Brian X. Tierney

*By:	/s/ Brian X. Tierney **(Brian X. Tierney, Attorney-in-Fact)**	February 21, 2019

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Indiana Michigan Power Company

By: /s/ Brian X. Tierney
(Brian X. Tierney, Vice President and Chief Financial Officer)

Date: February 21, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ Nicholas K. Akins **(Nicholas K. Akins)**	Chairman of the Board, Chief Executive Officer and Director	February 21, 2019
(ii) Principal Financial Officer:		
/s/ Brian X. Tierney **(Brian X. Tierney)**	Vice President, Chief Financial Officer and Director	February 21, 2019
(iii) Principal Accounting Officer:		
/s/ Joseph M. Buonaiuto **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	February 21, 2019
(iv) A Majority of the Directors:		
*Nicholas K. Akins *Lisa M. Barton *Nicholas M. Elkins *Thomas A. Kratt *Marc E. Lewis *David A. Lucas *Mark C. McCullough *Carla E. Simpson *Toby L. Thomas Brian X. Tierney		
*By: /s/ Brian X. Tierney **(Brian X. Tierney, Attorney-in-Fact)**		February 21, 2019

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

AEP Transmission Company, LLC

By: /s/ Brian X. Tierney
(Brian X. Tierney, Vice President, Chief Financial Officer, and Manager)

Date: February 21, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ Nicholas K. Akins **(Nicholas K. Akins)**	Chairman of the Board, Chief Executive Officer and Manager	February 21, 2019
(ii) Principal Financial Officer:		
/s/ Brian X. Tierney **(Brian X. Tierney)**	Vice President, Chief Financial Officer and Manager	February 21, 2019
(iii) Principal Accounting Officer:		
/s/ Joseph M. Buonaiuto **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	February 21, 2019
(iv) A Majority of the Managers:		
*Nicholas K. Akins *David M. Feinberg *Mark C. McCullough *A. Wade Smith Brian X. Tierney		
*By: /s/ Brian X. Tierney **(Brian X. Tierney, Attorney-in-Fact)**		February 21, 2019

INDEX OF FINANCIAL STATEMENT SCHEDULES

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON FINANCIAL STATEMENT SCHEDULES

To the Board of Directors and Shareholders of
American Electric Power Company, Inc.

Our audits of the consolidated financial statements referred to in our report dated February 21, 2019 appearing in the 2018 Annual Report to Shareholders of American Electric Power Company, Inc. (which report and consolidated financial statements are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the accompanying schedule of condensed financial information and the schedule of valuation and qualifying accounts and reserves as of December 31, 2018 and 2017 and for each of the two years in the period ended December 31, 2018. In our opinion, these financial statement schedules as of December 31, 2018 and 2017 and for each of the two years in the period ended December 31, 2018 present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 21, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
American Electric Power Company, Inc.:

We have audited the consolidated statements of income, comprehensive income (loss), changes in equity, and cash flows of American Electric Power Company, Inc. and subsidiary companies (the "Company") for the year ended December 31, 2016, and have issued our report thereon dated February 27, 2017; such consolidated financial statements and report are included in the Company's 2018 Annual Report and are incorporated herein by reference. Our audit also included the 2016 financial statement schedules of the Company listed in Item 15. These financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion based on our audit. In our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2017

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED STATEMENTS OF INCOME
For the Years Ended December 31, 2018, 2017 and 2016
(in millions, except per-share and share amounts)

	Years Ended December 31, 2018	2017	2016
REVENUES			
Affiliated Revenues	$ 9.5	$ 9.1	$ 9.7
Other Revenues	1.4	5.9	2.8
TOTAL REVENUES	10.9	15.0	12.5
EXPENSES			
Other Operation	39.7	35.9	42.0
Asset Impairments and Other Related Charges	9.3	—	—
Depreciation	0.3	0.3	0.2
TOTAL EXPENSES	49.3	36.2	42.2
OPERATING LOSS	(38.4)	(21.2)	(29.7)
Other Income (Expense):			
Interest Income	31.3	20.5	11.3
Interest Expense	(87.5)	(43.1)	(26.8)
LOSS BEFORE INCOME TAX BENEFIT AND EQUITY EARNINGS	(94.6)	(43.8)	(45.2)
Income Tax Expense (Benefit)	(6.2)	0.1	(87.5)
Equity Earnings of Unconsolidated Subsidiaries	2,012.2	1,956.5	571.1
INCOME FROM CONTINUING OPERATIONS	1,923.8	1,912.6	613.4
LOSS FROM DISCONTINUED OPERATIONS, NET OF TAX	—	—	(2.5)
NET INCOME	1,923.8	1,912.6	610.9
Other Comprehensive Income (Loss)	(23.7)	88.5	(29.2)
TOTAL COMPREHENSIVE INCOME	$ 1,900.1	$ 2,001.1	$ 581.7
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	492,774,600	491,814,651	491,495,458
BASIC EARNINGS PER SHARE ATTRIBUTABLE TO COMMON SHAREHOLDERS FROM CONTINUING OPERATIONS	$ 3.90	$ 3.89	$ 1.25
BASIC LOSS PER SHARE ATTRIBUTABLE TO COMMON SHAREHOLDERS FROM DISCONTINUED OPERATIONS	—	—	(0.01)
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3.90	$ 3.89	$ 1.24
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	493,758,277	492,611,067	491,662,007
DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO COMMON SHAREHOLDERS FROM CONTINUING OPERATIONS	$ 3.90	$ 3.88	$ 1.25
DILUTED LOSS PER SHARE ATTRIBUTABLE TO COMMON SHAREHOLDERS FROM DISCONTINUED OPERATIONS	—	—	(0.01)
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3.90	$ 3.88	$ 1.24

See Condensed Notes to Condensed Financial Information beginning on page S-8.

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED BALANCE SHEETS
ASSETS
December 31, 2018 and 2017
(in millions)

	December 31, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$ 99.3	$ 132.1
Other Temporary Investments	2.3	2.0
Advances to Affiliates	1,096.4	989.5
Accounts Receivable:		
Affiliated Companies	6.4	2.5
General	7.6	7.6
Total Accounts Receivable	14.0	10.1
Accrued Tax Benefits	—	40.3
Prepayments and Other Current Assets	2.5	4.1
TOTAL CURRENT ASSETS	1,214.5	1,178.1
PROPERTY, PLANT AND EQUIPMENT		
General	2.2	1.8
Total Property, Plant and Equipment	2.2	1.8
Accumulated Depreciation and Amortization	1.2	0.8
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1.0	1.0
OTHER NONCURRENT ASSETS		
Investments in Unconsolidated Subsidiaries	21,522.3	19,720.8
Affiliated Notes Receivable	50.0	50.0
Deferred Charges and Other Noncurrent Assets	114.1	70.0
TOTAL OTHER NONCURRENT ASSETS	21,686.4	19,840.8
TOTAL ASSETS	$ 22,901.9	$ 21,019.9

See Condensed Notes to Condensed Financial Information beginning on page S-8.

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2018 and 2017
(dollars in millions)

	December 31, 2018	December 31, 2017
CURRENT LIABILITIES		
Advances from Affiliates	$ 313.6	$ 465.1
Accounts Payable:		
General	5.9	4.0
Affiliated Companies	4.2	6.1
Short-term Debt	1,160.0	898.6
Long-term Debt Due Within One Year – Nonaffiliated (a)	(2.0)	2.5
Accrued Taxes	13.2	—
Other Current Liabilities	16.5	9.9
TOTAL CURRENT LIABILITIES	1,511.4	1,386.2
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (a)	2,268.4	1,281.8
Deferred Credits and Other Noncurrent Liabilities	54.3	53.0
TOTAL NONCURRENT LIABILITIES	2,322.7	1,334.8
TOTAL LIABILITIES	3,834.1	2,721.0
MEZZANINE EQUITY		
Contingently Redeemable Performance Share Awards	39.4	11.9
COMMON SHAREHOLDERS' EQUITY		
Common Stock – Par Value – $6.50 Per Share:		
2018 / 2017		
Shares Authorized: 600,000,000 / 600,000,000		
Shares Issued: 513,450,036 / 512,210,644		
(20,204,160 and 20,205,046 Shares were Held in Treasury as of December 31, 2018 and December 31, 2017, Respectively)	3,337.4	3,329.4
Paid-in Capital	6,486.1	6,398.7
Retained Earnings	9,325.3	8,626.7
Accumulated Other Comprehensive Income (Loss)	(120.4)	(67.8)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	19,028.4	18,287.0
TOTAL LIABILITIES, MEZZANINE EQUITY AND SHAREHOLDERS' EQUITY	$ 22,901.9	$ 21,019.9

(a) *Amounts reflect the impact of fair value hedge accounting. See "Accounting for Fair Value Hedging Strategies" section of Note 10 included in the 2018 Annual Reports for additional information.*

See Condensed Notes to Condensed Financial Information beginning on page S-8.

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31, 2018	2017	2016
OPERATING ACTIVITIES			
Net Income	$ 1,923.8	$ 1,912.6	$ 610.9
Loss from Discontinued Operations	—	—	(2.5)
Income from Continuing Operations	1,923.8	1,912.6	613.4
Adjustments to Reconcile Income from Continuing Operations to Net Cash Flows from Continuing Operating Activities:			
Depreciation and Amortization	0.3	0.3	0.2
Deferred Income Taxes	(45.0)	33.7	(54.1)
Asset Impairments and Other Related Charges	9.3	—	—
Equity Earnings of Unconsolidated Subsidiaries	(2,012.2)	(1,956.5)	(571.1)
Cash Dividends Received from Unconsolidated Subsidiaries	855.6	827.0	859.1
Change in Other Noncurrent Assets	(5.5)	(0.4)	(1.0)
Change in Other Noncurrent Liabilities	42.1	74.0	13.8
Changes in Certain Components of Continuing Working Capital:			
Accounts Receivable, Net	(3.9)	51.5	11.1
Accounts Payable	—	1.6	2.4
Other Current Assets	47.8	70.0	(33.3)
Other Current Liabilities	4.7	0.7	(1.7)
Net Cash Flows from Continuing Operating Activities	817.0	1,014.5	838.8
INVESTING ACTIVITIES			
Construction Expenditures	(0.4)	(0.7)	(0.4)
Change in Advances to Affiliates, Net	(106.9)	(76.4)	(276.2)
Capital Contributions to Unconsolidated Subsidiaries	(859.1)	(563.2)	(310.2)
Return of Capital Contributions from Unconsolidated Subsidiaries	199.7	263.3	—
Issuance of Notes Receivable to Affiliated Companies	—	(30.0)	—
Net Cash Flows Used for Continuing Investing Activities	(766.7)	(407.0)	(586.8)
FINANCING ACTIVITIES			
Issuance of Common Stock, Net	73.6	12.2	34.2
Issuance of Long-term Debt	991.9	992.3	—
Commercial Paper and Credit Facility Borrowings	205.6	—	—
Change in Short-term Debt, Net	261.4	(141.4)	915.0
Retirement of Long-term Debt	—	(550.0)	—
Change in Advances from Affiliates, Net	(151.5)	266.7	(46.2)
Commercial Paper and Credit Facility Repayments	(205.6)	—	—
Dividends Paid on Common Stock	(1,251.1)	(1,175.4)	(1,115.7)
Other Financing Activities	(7.4)	(5.1)	(4.8)
Net Cash Flows Used for Continuing Financing Activities	(83.1)	(600.7)	(217.5)
Net Cash Flows Used for Discontinued Operating Activities	—	—	(2.5)
Net Cash Flows from Discontinued Investing Activities	—	—	—
Net Cash Flows from Discontinued Financing Activities	—	—	—
Net Increase (Decrease) in Cash and Cash Equivalents	(32.8)	6.8	32.0
Cash and Cash Equivalents at Beginning of Period	132.1	125.3	93.3
Cash and Cash Equivalents at End of Period	$ 99.3	$ 132.1	$ 125.3

See Condensed Notes to Condensed Financial Information beginning on page S-8.

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL INFORMATION

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The condensed financial information of Parent is required as a result of the restricted net assets of AEP consolidated subsidiaries exceeding 25% of AEP consolidated net assets as of December 31, 2018. Parent is a public utility holding company that owns all of the outstanding common stock of its public utility subsidiaries and varying percentages of other subsidiaries, including joint ventures and equity investments. The primary source of income for Parent is equity in its subsidiaries' earnings. Its major source of cash is dividends from the subsidiaries. Parent borrows the funds for the money pool that is used by the subsidiaries for their short-term cash needs.

Income Taxes

Parent files a consolidated federal income tax return with its subsidiaries. AEP System's current consolidated federal income tax is allocated to AEP System companies so that their current tax expense reflects a separate return result for each company in the consolidated group. The tax benefit of Parent is allocated to its subsidiaries with taxable income.

2. COMMITMENTS, GUARANTEES AND CONTINGENCIES

Parent and its subsidiaries are parties to environmental and other legal matters. For further discussion, see Note 6 - Commitments, Guarantees and Contingencies included in the 2018 Annual Report.

3. FINANCING ACTIVITIES

The following details long-term debt outstanding as of December 31, 2018 and 2017:

Long-term Debt

Type of Debt and Maturity	Weighted-Average Interest Rate as of December 31, 2018	Interest Rate Ranges as of December 31, 2018	2017	Outstanding as of December 31, 2018	2017
				(in millions)	
Senior Unsecured Notes					
2020-2028	3.30%	2.15%-4.30%	2.15%-3.20%	$ 2,266.4	$ 1,284.3
Total Long-term Debt Outstanding				2,266.4	1,284.3
Long-term Debt Due Within One Year				—	2.5
Long-term Debt				$ 2,266.4	$ 1,281.8

Long-term debt outstanding as of December 31, 2018 is payable as follows:

	2019	2020	2021	2022	2023	After 2023	Total
				(in millions)			
Principal Amount (a)	$ (2.0)	$ 498.6	$ 399.2	$ 299.2	$ (1.2)	$ 1,088.7	$ 2,282.5
Unamortized Discount, Net and Debt Issuance Costs							(16.1)
Total Long-term Debt Outstanding							$ 2,266.4

(a) Amounts reflect the impact of fair value hedge accounting. See "Accounting for Fair Value Hedging Strategies" section of Note 10 included in the 2018 Annual Report for additional information.

Short-term Debt

Parent's outstanding short-term debt was as follows:

	December 31, 2018		December 31, 2017	
Type of Debt	**Outstanding Amount**	**Weighted-Average Interest Rate**	**Outstanding Amount**	**Weighted-Average Interest Rate**
	(in millions)		**(in millions)**	
Commercial Paper	$ 1,160.0	2.96%	$ 898.6	1.85%
Total Short-term Debt	$ 1,160.0		$ 898.6	

4. RELATED PARTY TRANSACTIONS

Payments on Behalf of Subsidiaries

Due to occasional time sensitivity and complexity of payments, Parent makes certain insurance, tax and benefit payments on behalf of subsidiary companies. Parent is then fully reimbursed by the subsidiary companies.

Short-term Lending to Subsidiaries

Parent uses a commercial paper program to meet the short-term borrowing needs of subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds certain nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The program also allows some direct borrowers to invest excess cash with Parent.

Interest expense related to Parent's short-term borrowing is included in Interest Expense on Parent's statements of income. Parent incurred interest expense for amounts borrowed from subsidiaries of $11 million, $8 million and $2 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Interest income related to Parent's short-term lending is included in Interest Income on Parent's statements of income. Parent earned interest income for amounts advanced to subsidiaries of $27 million, $16 million and $10 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Affiliated Notes

Parent issued long-term debt, portions of which were loaned to its subsidiaries. Parent pays interest on the affiliated notes, but the subsidiaries accrue interest for their share of the affiliated borrowing and remit the interest to Parent. Interest income related to Parent's loans to subsidiaries is included in Interest Income on Parent's statements of income. Parent earned interest income on loans to subsidiaries of $2 million, $2 million and $1 million for the years ended December 31, 2018, 2017 and 2016, respectively.

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

AEP

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in millions)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2018	$ 38.5	$ 37.3	$ 2.6	$ 41.6	$ 36.8
Year Ended December 31, 2017	37.9	34.0	2.5	35.9	38.5
Year Ended December 31, 2016	29.0	40.7	2.6	34.4	37.9

(a) Recoveries offset by reclasses to other assets and liabilities.
(b) Uncollectible accounts written off.

Schedule II for the Registrant Subsidiaries is not presented because the amounts are not material.

INDEX OF AEP TRANSMISSION COMPANY, LLC (AEPTCO PARENT)
FINANCIAL STATEMENT SCHEDULES

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON FINANCIAL STATEMENT SCHEDULE

To the Board of Directors and Member of
AEP Transmission Company, LLC

Our audits of the consolidated financial statements referred to in our report dated February 21, 2019 appearing in the 2018 Annual Report to the Member of AEP Transmission Company, LLC (which report and consolidated financial statements are incorporated by reference in this Annual Report on Form 10-K) also included an audit of the accompanying schedule of condensed financial information as of December 31, 2018 and 2017 and for each of the two years in the period ended December 31, 2018. In our opinion, this financial statement schedule as of December 31, 2018 and 2017 and for each of the two years in the period ended December 31, 2018 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

The financial statement schedule of the Company for the year ended December 31, 2016 was audited by other auditors whose report, dated April 4, 2017, expressed an unqualified opinion on that financial statement schedule.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 21, 2019

SCHEDULE I
AEP TRANSMISSION COMPANY, LLC (AEPTCo Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED STATEMENTS OF INCOME
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31,		
	2018	**2017**	**2016**
EXPENSES			
Other Operation	$ —	$ —	$ 0.8
TOTAL EXPENSES	—	—	0.8
OPERATING LOSS	—	—	(0.8)
Other Income (Expense):			
Interest Income – Affiliated	104.6	82.9	57.8
Interest Expense	(103.4)	(82.4)	(57.9)
INCOME (LOSS) BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	1.2	0.5	(0.9)
Income Tax Expense (Benefit)	0.2	0.2	(0.3)
Equity Earnings of Unconsolidated Subsidiaries	314.9	270.4	193.3
NET INCOME	$ 315.9	$ 270.7	$ 192.7

The 2017 amounts presented reflect the revisions made to AEPTCo's previously issued financial statements.

See Condensed Notes to Condensed Financial Information beginning on page S-18.

SCHEDULE I
AEP TRANSMISSION COMPANY, LLC (AEPTCo Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED BALANCE SHEETS
ASSETS
December 31, 2018 and 2017
(in millions)

	December 31,	
	2018	**2017**
CURRENT ASSETS		
Advances to Affiliates	$ 17.0	$ 22.5
Accounts Receivable:		
Affiliated Companies	17.1	17.3
Total Accounts Receivable	17.1	17.3
TOTAL CURRENT ASSETS	34.1	39.8
OTHER NONCURRENT ASSETS		
Notes Receivable – Affiliated	2,823.0	2,550.4
Investments in Unconsolidated Subsidiaries	3,571.1	2,592.1
TOTAL OTHER NONCURRENT ASSETS	6,394.1	5,142.5
TOTAL ASSETS	$ 6,428.2	$ 5,182.3

The 2017 amounts presented reflect the revisions made to AEPTCo's previously issued financial statements.

See Condensed Notes to Condensed Financial Information beginning on page S-18.

SCHEDULE I
AEP TRANSMISSION COMPANY, LLC (AEPTCo Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2018 and 2017
(in millions)

	December 31, 2018	December 31, 2017
CURRENT LIABILITIES		
Accounts Payable:		
General	$ 0.3	$ 0.4
Affiliated Companies	17.7	24.0
Long-term Debt Due Within One Year – Nonaffiliated	85.0	50.0
Accrued Taxes	0.1	0.1
Accrued Interest	15.9	15.0
Other Current Liabilities	1.4	2.5
TOTAL CURRENT LIABILITIES	120.4	92.0
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,738.0	2,500.4
TOTAL NONCURRENT LIABILITIES	2,738.0	2,500.4
TOTAL LIABILITIES	2,858.4	2,592.4
MEMBER'S EQUITY		
Paid-in Capital	2,480.6	1,816.6
Retained Earnings	1,089.2	773.3
TOTAL MEMBER'S EQUITY	3,569.8	2,589.9
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 6,428.2	$ 5,182.3

The 2017 amounts presented reflect the revisions made to AEPTCo's previously issued financial statements.

See Condensed Notes to Condensed Financial Information beginning on page S-18.

SCHEDULE I
AEP TRANSMISSION COMPANY, LLC (AEPTCo Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31,		
	2018	**2017**	**2016**
OPERATING ACTIVITIES			
Net Income	$ 315.9	$ 270.7	$ 192.7
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Deferred Income Taxes	—	1.6	(1.7)
Equity Earnings of Unconsolidated Subsidiaries	(314.9)	(270.4)	(193.3)
Change in Other Noncurrent Assets	—	—	0.2
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	0.2	4.5	2.2
Accounts Payable	(6.4)	5.4	2.8
Accrued Taxes, Net	—	0.1	0.1
Accrued Interest	0.9	4.5	2.6
Other Current Liabilities	(1.2)	(8.1)	(5.5)
Net Cash Flows from (Used for) Operating Activities	(5.5)	8.3	0.1
INVESTING ACTIVITIES			
Change in Advances to Affiliates, Net	5.5	(8.3)	(0.1)
Issuance of Notes Receivable to Affiliated Companies	(271.0)	(617.6)	(686.9)
Repayments of Notes Receivable from Affiliated Companies	—	—	300.0
Capital Contributions to Subsidiaries	(664.0)	(361.6)	(212.0)
Net Cash Flows Used for Investing Activities	(929.5)	(987.5)	(599.0)
FINANCING ACTIVITIES			
Capital Contribution from Member	664.0	361.6	212.0
Issuance of Long-term Debt – Nonaffiliated	321.0	617.6	686.9
Retirement of Long-term Debt – Nonaffiliated	(50.0)	—	(300.0)
Net Cash Flows from Financing Activities	935.0	979.2	598.9
Net Change in Cash and Cash Equivalents	—	—	—
Cash and Cash Equivalents at Beginning of Period	—	—	—
Cash and Cash Equivalents at End of Period	$ —	$ —	$ —

The 2017 amounts presented reflect the revisions made to AEPTCo's previously issued financial statements.

See Condensed Notes to Condensed Financial Information beginning on page S-18.

SCHEDULE I
AEP TRANSMISSION COMPANY, LLC (AEPTCo Parent)
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL INFORMATION

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The condensed financial information of AEPTCo Parent is required as a result of the restricted net assets of AEPTCo consolidated subsidiaries exceeding 25% of AEPTCo consolidated net assets as of December 31, 2018. AEPTCo Parent is the direct holding company for the seven State Transcos. The primary source of income for AEPTCo Parent is equity in its subsidiaries' earnings.

Income Taxes

AEPTCo Parent joins in the filing of a consolidated federal income tax return with its affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The tax benefit of AEP Parent is allocated to its subsidiaries with taxable income.

Revisions to Previously Issued Financial Statements

During 2018, management identified certain transmission assets that it believes should not have been included in AEPTCo's SPP transmission formula rates since 2013. Additionally, during 2018, management determined that AFUDC was improperly capitalized and that revenue should not have been recorded related to that AFUDC dating back to 2011. Accordingly, management revised the historical 2017 period of AEPTCo Parent's financial statements included in Schedule I - Condensed Financial Information. The statements of income reflect the adjustments to Equity Earnings of Unconsolidated Subsidiaries and Net Income of $(15) million. The balance sheets reflect the adjustments to Investments in Unconsolidated Subsidiaries and Retained Earnings of $(15) million. The statements of cash flows reflect the adjustments to Net Income and Equity Earnings of Unconsolidated Subsidiaries of $(15) million. The effects of recording these adjustments in 2017 are not material to AEPTCo Parent's financial statements for 2017 or any earlier period. See the "Revisions to Previously Issued Financial Statements" section of Note 1 included in the 2018 Annual Reports for additional information.

2. COMMITMENTS, GUARANTEES AND CONTINGENCIES

AEPTCo Parent and its subsidiaries are parties to legal matters. For further discussion, see Note 6 - Commitments, Guarantees and Contingencies included in the 2018 Annual Report.

3. FINANCING ACTIVITIES

For discussion of Financing Activities, see Note 14 - Financing Activities to AEPTCo's audited consolidated financial statements included in the 2018 Annual Report.

4. RELATED PARTY TRANSACTIONS

Payments on Behalf of Subsidiaries

Due to occasional time sensitivity and complexity of payments, Parent makes certain insurance, tax and other payments on behalf of subsidiary companies. Parent is then fully reimbursed by the subsidiary companies. AEPTCo Parent also makes convenience payments on behalf of its State Transcos. AEPTCo Parent is then fully reimbursed by its State Transcos.

Long-term Lending to Subsidiaries

AEPTCo Parent enters into debt arrangements with nonaffiliated entities. AEPTCo Parent has long-term debt of $2.8 billion and $2.6 billion as of December 31, 2018 and 2017, respectively. AEPTCo Parent uses the proceeds from these nonaffiliated debt arrangements to make affiliated loans to its State Transcos using the same interest rates and maturity dates as the nonaffiliated debt arrangements. AEPTCo Parent has recorded Notes Receivable – Affiliated of $2.8 billion and $2.6 billion as of December 31, 2018 and 2017, respectively. Related to these nonaffiliated and affiliated debt arrangements, AEPTCo Parent has recorded Accrued Interest of $16 million and $15 million as of December 31, 2018 and 2017, respectively. AEPTCo Parent has also recorded Accounts Receivable – Affiliated Companies of $17 million and $17 million as of December 31, 2018 and 2017, respectively. AEPTCo Parent has recorded Interest Income – Affiliated of $105 million, $83 million and $58 million for the years ended December 31, 2018, 2017 and 2016, respectively, related to the Notes Receivable – Affiliated. AEPTCo Parent has recorded Interest Expense of $103 million, $82 million and $58 million for the years ended December 31, 2018, 2017 and 2016, respectively, related to the nonaffiliated debt arrangements.

Short-term Lending to Subsidiaries

Parent uses a commercial paper program to meet the short-term borrowing needs of subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds certain nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The program also allows some direct borrowers to invest excess cash with Parent.

Interest expense related to AEPTCo Parent's short-term borrowing is included in Interest Expense on AEPTCo Parent's statements of income. AEPTCo Parent incurred immaterial interest expense for amounts borrowed from AEP affiliates for the years ended December 31, 2018, 2017 and 2016.

Interest income related to AEPTCo Parent's short-term lending is included in Interest Income – Affiliated on AEPTCo Parent's statements of income. AEPTCo Parent earned interest income for amounts advanced to AEP affiliates of $1 million and $1 million for the year ended December 31, 2018 and 2017, respectively. The amount for the year ended December 31, 2016 was immaterial.

EXHIBIT INDEX

The documents listed below are being filed or have previously been filed on behalf of the Registrants shown and are incorporated herein by reference to the documents indicated and made a part hereof. Exhibits ("Ex") not identified as previously filed are filed herewith. Exhibits designated with a dagger (†) are management contracts or compensatory plans or arrangements required to be filed as an Exhibit to this Form. Exhibits designated with an asterisk (*) are filed herewith.

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
AEP‡ File No. 1-3525		
3(a)	Composite of the Restated Certificate of Incorporation of AEP, dated April 23, 2015.	Form 10-Q, Ex 3, June 30, 2015
3(b)	Composite By-Laws of AEP, as amended as of October 20, 2015.	Form 8-K, Ex 3(b) dated October 21, 2015
4(a)	Indenture (for unsecured debt securities), dated as of May 1, 2001, between AEP and The Bank of New York, as Trustee.	Registration Statement No. 333-86050, Ex 4(a)(b)(c) Registration Statement No. 333-105532, Ex 4(d)(e)(f) Registration Statement No. 333-200956, Ex 4(b) Registration Statement No. 333-222068, Ex 4(b)
4(a)1	Company Order and Officers Certificate to The Bank of New York Mellon Trust Company, N.A. dated November 30, 2018 of 3.65% Senior Notes Series I due 2021 and 4.30% Senior Notes, Series J due 2028.	Form 8-K, Ex. 4(a) dated November 30, 2018
4(b)	First Amendment to Fourth Amended and Restated Credit Agreement dated June 30, 2016 among AEP, the banks, financial institutions and other institutional lenders listed on the signature pages thereof and Wells Fargo Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 4, September 30, 2018
10(a)	Lease Agreements, dated as of December 1, 1989, between AEGCo or I&M and Wilmington Trust Company, as amended.	Registration Statement No. 33-32752, Ex 28(c)(1-6)(C) Registration Statement No. 33-32753, Ex 28(a)(1-6)(C) AEGCo 1993 Form 10-K, Ex 10(c)(1-6)(B) I&M 1993 Form 10-K, Ex 10(e)(1-6)(B)
10(b)	Consent Decree with U.S. District Court dated October 9, 2007, as modified.	Form 8-K, Ex 10.1 dated October 9, 2007 Form 10-Q, Ex 10, June 30, 2013
†10(c)	AEP Retainer Deferral Plan for Non-Employee Directors, as Amended and Restated effective July 26, 2016.	2016 Form 10-K, Ex 10(h)
†10(d)	AEP Stock Unit Accumulation Plan for Non-Employee Directors as amended July 26, 2016.	2016 Form 10-K, Ex 10(i)
†10(e)	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(l)(1)(A)
†10(e)(1)	Guaranty by AEP of AEPSC Excess Benefits Plan.	1990 Form 10-K, Ex 10(h)(1)(B)
†10(f)	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2011 (Non-Qualified).	2010 Form 10-K, Ex 10
†10(f)(1)(A)	Amendment to AEP System Supplemental Retirement Savings Plan, as Amended and Restated as of January 1, 2011 (Non-Qualified).	2014 Form 10-K, Ex 10(l)(1)(A)
†10(g)	AEPSC Umbrella Trust for Executives.	1993 Form 10-K, Ex 10(g)(3)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
†10(g)(1)(A)	First Amendment to AEPSC Umbrella Trust for Executives.	2008 Form 10-K, Ex 10(l)(3)(A)
*†10(g)(2)(A)	Second Amendment to AEPSC Umbrella Trust for Executives.	
†10(h)	AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(p)
†10(h)(1)(A)	First Amendment to AEP System Incentive Compensation Deferral Plan, as Amended and Restated effective January 1, 2008.	2011 Form 10-K, Ex 10(p)(1)(A)
†10(h)(2)(A)	Second Amendment to AEP System Incentive Compensation Deferral Plan, as Amended and Restated effective January 1, 2008.	2014 Form 10-K, Ex 10(q)(2)(A)
†10(i)	AEP Change In Control Agreement, as Revised Effective January 1, 2017.	Form 10-Q, Ex 10(c) , September 30, 2016
†10(j)	Amended and Restated AEP System Long-Term Incentive Plan as of September 21, 2016.	Form 10-Q, Ex 10(a) , September 30, 2016
†10(j)(1)(A)	Performance Share Award Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	Form 10-Q, Ex 10(a), March 30, 2018
†10(j)(2)(A)	Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan as Amended and Restated.	Form 10-Q, Ex 10(b), March 30, 2018
†10(k)	AEP System Stock Ownership Requirement Plan Amended and Restated effective June 20, 2017.	Form 10-Q, Ex 10, June 30, 2017
†10(l)	Central and South West System Special Executive Retirement Plan Amended and Restated effective January 1, 2009.	2008 Form 10-K, Ex 10(v)
†10(m)	AEP Executive Severance Plan Amended and Restated effective October 24, 2016.	Form 10-Q, Ex 10(d) , September 30, 2016
†10(n)	Letter Agreement dated November 20, 2012 between AEPSC and Lana Hillebrand.	2013 Form 10-K, Ex 10(x)
†10(o)	AEP Aircraft Timesharing Agreement dated September 17, 2018 between American Electric Power Service Corporation and Nicholas K. Akins.	Form 10-Q, Ex 10, September 30, 2018
*13	Copy of those portions of the AEP 2018 Annual Report (for the fiscal year ended December 31, 2018) which are incorporated by reference in this filing.	
*21	List of subsidiaries of AEP.	
*23 (1)	Consent of PricewaterhouseCoopers LLP.	
*23 (2)	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
101.INS	XBRL Instance Document.	
101.SCH	XBRL Taxonomy Extension Schema.	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.	
101.DEF	XBRL Taxonomy Extension Definition Linkbase.	
101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
AEP TEXAS‡ File No. 333-221643		
3(a)	Composite of the Restated Certificate of Incorporation, as amended.	Registration No. 333-221643, Ex 3(a)
3(b)	Bylaws.	Registration No. 333-221643, Ex 3(b)
4(a)(1)	Indenture, dated as of September 1, 2017, between AEP Texas Inc. and The Bank of New York Mellon Trust Company, N.A., as Trustee.	Registration No. 333-221643, Ex 4(a)-1,4(a)-2 Form 8-K, Ex 4(a) dated May 17, 2018
4(a)(2)	Company Order and Officers' Certificate to The Bank of New York Mellon Trust Company, N.A. dated January 11, 2018 of 2.40% Senior Notes, Series C due 2022 and 3.80% Senior Notes, Series D due 2047	2017 Form 10-K, Ex4(a)(3)
4(a)(3)	Second Supplemental Indenture dated as of May 17, 2018, between AEP Texas Inc. and The Bank of New York Mellon Trust Company, N.A., as Trustee of 3.950 Senior Notes, Series E due 2028.	Form 8-K, Ex 4(a) dated May 17, 2018
4(a)(4)	Company Order and Officer's Certificate to The Bank of New York Mellon Trust Company, N.A. dated January 24, 2019 of 3.950% Senior Notes, Series F due 2028.	Form 8-K, Ex 4(a) dated January 24, 2019
*13	Copy of those portions of the AEP Texas 2018 Annual Report (for the fiscal year ended December 31, 2018) which are incorporated by reference in this filing.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
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101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
AEPTCo‡ File No. 333-217143		
3(a)	Limited Liability Company Agreement of AEP Transmission Company, LLC dated as of January 27, 2006.	Registration Statement No. 333-217143, Ex 3(a)
3(b)	First Amendment to Limited Liability Company Agreement dated as of May 21, 2013.	Registration Statement No. 333-217143, Ex 3(b)
4(a)(1)	Indenture, dated as of November 1, 2016, between AEP Transmission Company, LLC and The Bank of New York Mellon Trust Company, N.A., as Trustee.	Registration Statement No. 333-217143, Ex 4(a)-1, 4(a)-2 Registration Statement No. 333-225325, Ex 4(b)(c)(d)
4(a)(2)	Company Order and Officers' Certificate to The Bank of New York Mellon Trust Company, N.A. dated September 7, 2018 of 4.25% Senior Notes, Series J due 2048.	Form 8-K, Ex 4(a) dated September 7, 2018
4(c)(1)	Note Purchase Agreement, dated as of October 18, 2012 between AEP Transmission Company, LLC and the Initial Purchasers.	Registration Statement No. 333-217143, Ex 4(c)-1
4(c)(2)	Supplement to Note Purchase Agreement, dated as of November 7, 2013 between AEP Transmission Company, LLC and the Initial Purchasers.	Registration Statement No. 333-217143, Ex 4(c)-2
4(c)(3)	Supplement to Note Purchase Agreement, dated as of November 14, 2014 between AEP Transmission Company, LLC and the Initial Purchasers.	Registration Statement No. 333-217143, Ex 4(c)-3
*13	Copy of those portions of the AEPTCo 2018 Annual Report (for the fiscal year ended December 31, 2018) which are incorporated by reference in this filing.	
*23(1)	Consent of PricewaterhouseCoopers LLP.	
*23(2)	Consent of Deloitte & Touche LLP.	
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101.DEF	XBRL Taxonomy Extension Definition Linkbase.	
101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
APCo‡ File No. 1-3457		
3(a)	Composite of the Restated Articles of Incorporation of APCo, amended as of March 7, 1997.	1996 Form 10-K, Ex 3(d)
3(b)	Composite By-Laws of APCo, amended as of February 26, 2008.	2007 Form 10-K, Ex 3(b)
4(a)	Indenture (for unsecured debt securities), dated as of January 1, 1998, between APCo and The Bank of New York, As Trustee.	Registration Statement No. 333-45927, Ex 4(a)(b) Registration Statement No. 333-49071, Ex 4(b) Registration Statement No. 333-84061, Ex 4(b)(c) Registration Statement No. 333-100451, Ex 4(b) Registration Statement No. 333-116284, Ex 4(b)(c) Registration Statement No. 333-123348, Ex 4(b)(c) Registration Statement No. 333-136432, Ex 4(b)(c)(d) Registration Statement No. 333-161940, Ex 4(b)(c)(d) Registration Statement No. 333-182336, Ex 4(b)(c) Registration Statement No. 333-200750, Ex. 4(b)(c) Registration Statement No. 333-214448, Ex. 4(b)
4(a)(1)	Company Order and Officers Certificate to The Bank of New York Mellon Trust Company, N.A. dated May 11, 2017 of 3.30% Senior Notes Series X due 2027.	Form 8-K, Ex 4(a) dated May 11, 2017
10(a)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended September 10, 2010.	2013 Form 10-K, Ex 10(a)
10(d)	Consent Decree with U.S. District Court, as modified.	Form 8-K, Ex 10.1 dated October 9, 2007 Form 10-Q, Ex 10, June 30, 2013
*13	Copy of those portions of the APCo 2018 Annual Report (for the fiscal year ended December 31, 2018) which are incorporated by reference in this filing.	
*23 (1)	Consent of PricewaterhouseCoopers LLP.	
*23 (2)	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
101.INS	XBRL Instance Document.	
101.SCH	XBRL Taxonomy Extension Schema.	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.	
101.DEF	XBRL Taxonomy Extension Definition Linkbase.	
101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
I&M‡ File No. 1-3570		
3(a)	Composite of the Amended Articles of Acceptance of I&M, dated of March 7, 1997.	1996 Form 10-K, Ex 3(c)
3(b)	Composite By-Laws of I&M, amended as of February 26, 2008.	2007 Form 10-K, Ex 3(b)
4(a)	Indenture (for unsecured debt securities), dated as of October 1, 1998, between I&M and The Bank of New York, as Trustee.	Registration Statement No. 333-88523, Ex 4(a)(b)(c) Registration Statement No. 333-58656, Ex 4(b)(c) Registration Statement No. 333-108975, Ex 4(b)(c)(d) Registration Statement No. 333-136538, Ex 4(b)(c) Registration Statement No. 333-156182, Ex 4(b) Registration Statement No. 333-185087, Ex 4(b) Registration Statement No. 333-207836, Ex 4(b) Registration Statement No. 333-225103, Ex 4(b)(c)(d)
4(b)	Company Order and Officers Certificate to The Bank of New York Mellon Trust Company, N.A. dated August 8, 2018 of 4.25% Series N due 2048.	Form 8-K, Ex 4(a) dated August 8, 2018
10(a)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended September 10, 2010.	2013 Form 10-K, Ex 10(a)
10(b)	Unit Power Agreement dated as of March 31, 1982 between AEGCo and I&M, as amended.	Registration Statement No. 33-32752, Ex 28(b)(1)(A)(B)
10(c)	Consent Decree with U.S. District Court, as modified.	Form 8-K, Ex 10.1 dated October 9, 2007 Form 10-Q, Ex 10, June 30, 2013
10(d)	Lease Agreements, dated as of December 1, 1989, between I&M and Wilmington Trust Company, as amended.	Registration Statement No. 33-32753, Ex 28(a)(1-6)(C) 1993 Form 10-K, Ex 10(e)(1-6)(B)
*13	Copy of those portions of the I&M 2018 Annual Report (for the fiscal year ended December 31, 2018) which are incorporated by reference in this filing.	
*23 (1)	Consent of PricewaterhouseCoopers LLP.	
*23 (2)	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
101.INS	XBRL Instance Document.	
101.SCH	XBRL Taxonomy Extension Schema.	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.	
101.DEF	XBRL Taxonomy Extension Definition Linkbase.	
101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
OPCo‡ File No.1-6543		
3(a)	Composite of the Amended Articles of Incorporation of OPCo, dated June 3, 2002.	Form 10-Q, Ex 3(e), June 30, 2002
3(b)	Amended Code of Regulations of OPCo.	Form 10-Q, Ex 3(b), June 30, 2008
4(a)	Indenture (for unsecured debt securities), dated as of September 1, 1997, between OPCo and Bankers Trust Company (now The Bank of New York Mellon Trust Company, N.A. as assignee of Deutsche Bank Trust Company Americas), as Trustee.	Registration Statement No. 333-49595, Ex 4(a)(b)(c) Registration Statement No. 333-106242, Ex 4(b)(c)(d) Registration Statement No. 333-127913, Ex 4(b)(c) Registration Statement No. 333-139802, Ex 4(b)(c)(d) Registration Statement No. 333-161537, Ex 4(b)(c)(d) Registration Statement No. 333-211192, Ex 4(b)
4a(1)	Resignation of Deutsche Bank Trust Company Americas, as Trustee and appointment of The Bank of New York Mellon Trust Company, N.A. as Trustee of Indenture with OPCo dated as of September 1, 1997.	Form 8-K, Item 8.01 dated October 8, 2018
4(c)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between OPCo and Bank One, N.A., as Trustee.	Registration Statement No. 333-127913, Ex 4(d)(e)(f)
4(d)	Indenture (for unsecured debt securities), dated as of September 1, 1997, between CSPCo (predecessor in interest to OPCo) and Bankers Trust Company, as Trustee.	Registration Statement No. 333-54025, Ex 4(a)(b)(c)(d) Registration Statement No. 333-128174, Ex 4(b)(c)(d) Registration Statement No. 333-150603, Ex 4(b)
4(e)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between CSPCo (predecessor in interest to OPCo) and Bank One, N.A., as Trustee.	Registration Statement No. 333-128174, Ex 4(e)(f)(g) Registration Statement No. 333-150603, Ex 4(b)
4(f)	First Supplemental Indenture, dated as of December 31, 2011, by and between OPCo and The Bank of New York Mellon Trust Company, N.A., as trustee, supplementing the Indenture dated as of September 1, 1997 between CSPCo (predecessor in interest to OPCo) and the trustee.	Form 8-K, Ex 4.1 dated January 6, 2012

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
4(g)	Third Supplemental Indenture, dated as of December 31, 2011, by and between OPCo and The Bank of New York Mellon Trust Company, N.A., as trustee, supplementing the Indenture dated as of February 14, 2003 between CSPCo (predecessor in interest to OPCo) and the trustee.	Form 8-K, Ex 4.2 dated January 6, 2012
4(h)	Company Order and Officers Certificate to The Bank of New York Mellon Trust Company, N.A. dated March 22, 2018 of 4.15% Series N due 2048.	Form 8-K, Ex 4(a), dated March 22, 2018
10(a)	Inter-Company Power Agreement, dated July 10, 1953, among OVEC and the Sponsoring Companies, as amended September 10, 2010.	2013 Form 10-K, Ex 10(a)
10(b)	Consent Decree with U.S. District Court, as modified.	Form 8-K, Item Ex 10.1 dated October 9, 2007 Form 10-Q, Ex 10, June 30, 2013
*13	Copy of those portions of the OPCo 2018 Annual Report (for the fiscal year ended December 31, 2018) which are incorporated by reference in this filing.	
*23 (1)	Consent of PricewaterhouseCoopers LLP.	
*23 (2)	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
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101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
PSO‡ File No. 0-343		
3(a)	Certificate of Amendment to Restated Certificate of Incorporation of PSO.	Form 10-Q, Ex 3(a), June 30, 2008
3(b)	Composite By-Laws of PSO amended as of February 26, 2008.	2007 Form 10-K, Ex 3 (b)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
4(a)	Indenture (for unsecured debt securities), dated as of November 1, 2000, between PSO and The Bank of New York, as Trustee.	Registration Statement No. 333-100623, Ex 4(a)(b) Registration Statement No. 333-114665, Ex 4(b)(c) Registration Statement No. 333-133548, Ex 4(b)(c) Registration Statement No. 333-156319, Ex 4(b)(c)
4(b)	Eighth Supplemental Indenture, dated as of November 13, 2009 between PSO and The Bank of New York Mellon, as Trustee, establishing terms of the 5.15% Senior Notes, Series H, due 2019.	Form 8-K, Ex 4(a), dated November 13, 2009
4(c)	Ninth Supplemental Indenture, dated as of January 19, 2011 between PSO and The Bank of New York Mellon Trust Company, N.A., as Trustee, establishing terms of 4.40% Senior Notes, Series I, due 2021.	Form 8-K, Ex 4(a) dated January 20, 2011
*13	Copy of those portions of the PSO 2018 Annual Report (for the fiscal year ended December 31, 2018) which are incorporated by reference in this filing.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
101.INS	XBRL Instance Document.	
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101.DEF	XBRL Taxonomy Extension Definition Linkbase.	
101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
SWEPCo‡ File No. 1-3146		
3(a)	Composite of Amended Restated Certificate of Incorporation of SWEPCo.	2008 Form 10-K, Ex 3(a)
3(b)	Composite By-Laws of SWEPCo amended as of February 26, 2008.	2007 Form 10-K, Ex 3(b)
4(a)	Indenture (for unsecured debt securities), dated as of February 4, 2000, between SWEPCo and The Bank of New York, as Trustee.	Registration Statement No. 333-96213 Registration Statement No. 333-87834, Ex 4(a)(b) Registration Statement No. 333-100632, Ex 4(b) Registration Statement No. 333-108045, Ex 4(b) Registration Statement No. 333-145669, Ex 4(c)(d) Registration Statement No. 333-161539, Ex 4(b)(c) Registration Statement No. 333-194991, Ex 4(b)(c) Registration Statement No. 333-208535, Ex 4(b)(c) Registration Statement No. 333-226856, Ex 4(b)(c)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
4(b)	Thirteenth Supplemental Indenture, dated as of September 1, 208 between SWEPCo and The Bank of New York Mellon Trust Company, N.A., as Trustee, establishing terms of the 4.10% Senior Notes, Series M. Due 2028.	Form 8-K, Ex 4(a) dated September 13, 2018
*13	Copy of those portions of the SWEPCo 2018 Annual Report (for the fiscal year ended December 31, 2018) which are incorporated by reference in this filing.	
*23 (1)	Consent of PricewaterhouseCoopers LLP.	
*23 (2)	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*95	Mine Safety Disclosure.	
101.INS	XBRL Instance Document.	
101.SCH	XBRL Taxonomy Extension Schema.	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.	
101.DEF	XBRL Taxonomy Extension Definition Linkbase.	
101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	

‡ Certain instruments defining the rights of holders of long-term debt of the registrants included in the financial statements of registrants filed herewith have been omitted because the total amount of securities authorized thereunder does not exceed 10% of the total assets of registrants. The registrants hereby agree to furnish a copy of any such omitted instrument to the SEC upon request.

The agreements and other documents filed as exhibits to this report are not intended to provide factual information or other disclosure other than with respect to the terms of the agreements or other documents themselves, and you should not rely on them for that purpose. In particular, any representations and warranties made by us in these agreements or other documents were made solely within the specific context of the relevant agreement or document and may not describe the actual state of affairs as of the date they were made or at any other time.

Exhibit 10(g)(2)(A)

SECOND AMENDMENT
To the
American Electric Power Service Corporation Umbrella Trust™ For Executives

This Amendment is made by and between American Electric Power Service Corporation, a New York corporation (the "Company") and Wells-Fargo Bank (as successor in interest to Harris Trust and Savings Bank) (the "Trustee") to the Trust Agreement entitled the American Electric Power Service Corporation Umbrella Trust™ For Executives that was signed by the Company as of May 27, 1993 and by Harris Trust and Savings Bank as of June 9, 1993 (the "Trust Agreement"), as amended, including the First Amendment thereto dated last December 17, 2007.

PREAMBLE

A. Pursuant to the Trust Agreement, the Company established a trust with the Trustee to hold monies and other property, together with the income thereon, for the uses and purposes and upon the terms and conditions set forth therein, including, primarily, in connection with the administration of the American Electric Power System Excess Benefit Plan and certain employment agreements and deferred compensation agreements, but over time the Company and its affiliates have satisfied the obligations under the employment agreements and certain deferred compensation agreements, while also adding certain additional plans to the protections afforded under the Trust Agreement.

B. Section 7.02-1 of the Trust Agreement provides that the Company and the trustee may amend the Trust Agreement prior to a Special Circumstance (as defined in the trust Agreement) without the written consent of the Plan participants if such amendment does not have a material adverse effect on the rights of any participant.

F. The Company and the Trustee, acknowledging that neither has knowledge that any such Special Circumstance has occurred, wish to amend the Trust Agreement to clarify the programs to which it is currently applicable and to permit broader flexibility for the diversification of the investment of the assets held in the Trust.

AMENDMENT

1. Replace the first paragraph of the Preamble to the AEP Umbrella Trust with the following:

"The following three (3) plans originally were subject to this trust:

- American Electric Power System Excess Benefit Plan the "AEP SERP"),
- Employment Agreements as listed in Appendix Exhibit B attached to the original Trust Agreement, and
- 1982 and 1986 Deferred Compensation Agreements as listed in Appendix Exhibit C attached to the original Trust Agreement.

Prior to the effective date of this Amendment, the Company has satisfied its liability under each of the Employment Agreements and each of the 1982 and 1986 Deferred Compensation Agreements listed in Appendix Exhibits B and C, respectively.

Effective since June 1996, the Company caused the following plans to become subject to this trust:

- American Electric Power System Supplemental Retirement Savings Plan (the "AEP SRSP"),
- Management Incentive Compensation Plan Voluntary Deferrals ("MICP Deferrals"), in which as of the effective date of this Amendment, only two participants maintain an account to which such deferrals are credited, and
- Performance Share Incentive Plan Restricted Stock Units (which are now called "Career Shares" administered under the American Electric Power System Stock Ownership Requirement Plan ("SORP")."

2. Replace the first sentence of Section 2.02-1 of the Trust with the following:

"The trust fund shall be invested in such investments as are permitted under this Section 2.02, provided that the trust fund may be, but shall not be required to be, invested primarily in insurance contracts ("Contracts") of which the Trust shall be sole owner and beneficiary."

IN WITNESS WHEREOF, the Company and the Trustee have caused this Amendment to be executed by their respective duly authorized officers on the dates set forth below.

American Electric Power Service Corporation

By: /s/ Aaron A. Hill

Title: Director Trusts & Investments

Date: September 20, 2018

Wells Fargo Bank

By: /s/ Heather E. Lineaweaver

Title: Assistant Vice President

Date: September 19, 2018

2018 Annual Reports

American Electric Power Company, Inc. and Subsidiary Companies

AEP Texas Inc. and Subsidiaries

AEP Transmission Company, LLC and Subsidiaries

Appalachian Power Company and Subsidiaries

Indiana Michigan Power Company and Subsidiaries

Ohio Power Company and Subsidiaries

Public Service Company of Oklahoma

Southwestern Electric Power Company Consolidated

Audited Financial Statements and
Management's Discussion and Analysis of Financial Condition and Results of Operations

AMERICAN ELECTRIC POWER®

BOUNDLESS ENERGY℠

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF ANNUAL REPORTS

GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP Energy	AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEP Texas	AEP Texas Inc., an AEP electric utility subsidiary.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEP Utilities	AEP Utilities, Inc., a former subsidiary of AEP and holding company for TCC, TNC and CSW Energy, Inc. Effective December 31, 2016, TCC and TNC were merged into AEP Utilities, Inc. Subsequently following this merger, the assets and liabilities of CSW Energy, Inc. were transferred to a competitive affiliate company and AEP Utilities, Inc. was renamed AEP Texas Inc.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, hedging activities, asset management and commercial and industrial sales in the deregulated Ohio and Texas markets.
AEPRO	AEP River Operations, LLC, a commercial barge operation sold in November 2015.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a wholly-owned subsidiary of AEP Transmission Holdco, is an intermediate holding company that owns the State Transcos.
AEPTCo Parent	AEP Transmission Company, LLC, the holding company of the State Transcos within the AEPTCo consolidation.
AFUDC	Allowance for Funds Used During Construction.
AGR	AEP Generation Resources Inc., a competitive AEP subsidiary in the Generation & Marketing segment.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
Appalachian Consumer Rate Relief Funding	Appalachian Consumer Rate Relief Funding LLC, a wholly-owned subsidiary of APCo and a consolidated variable interest entity formed for the purpose of issuing and servicing securitization bonds related to the under-recovered ENEC deferral balance.
APSC	Arkansas Public Service Commission.
ARAM	Average Rate Assumption Method, an IRS approved method used to calculate the reversal of Excess ADIT for ratemaking purposes.
ARO	Asset Retirement Obligations.
ASC	Accounting Standard Codification.
ASU	Accounting Standards Update.
CAA	Clean Air Act.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO_2	Carbon dioxide and other greenhouse gases.
Conesville Plant	A generation plant consisting of three coal-fired generating units totaling 1,695 MW located in Conesville, Ohio. The plant is jointly owned by AGR and a nonaffiliate.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,278 MW nuclear plant owned by I&M.

Term	Meaning
CRES provider	Competitive Retail Electric Service providers under Ohio law that target retail customers by offering alternative generation service.
CSAPR	Cross-State Air Pollution Rule.
CWA	Clean Water Act.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel VII, DCC Fuel VIII, DCC Fuel IX, DCC Fuel X, DCC Fuel XI and DCC Fuel XII consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DOE	U. S. Department of Energy.
Desert Sky	Desert Sky Wind Farm, a 168 MW wind electricity generation facility located on Indian Mesa in Pecos County, Texas.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
DIR	Distribution Investment Rider.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated variable interest entity of AEP.
ENEC	Expanded Net Energy Cost.
Energy Supply	AEP Energy Supply LLC, a nonregulated holding company for AEP's competitive generation, wholesale and retail businesses, and a wholly-owned subsidiary of AEP.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP Transmission Holdco and Berkshire Hathaway Energy Company formed to own and operate electric transmission facilities in ERCOT.
Excess ADIT	Excess accumulated deferred income taxes.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FIP	Federal Implementation Plan.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
Global Settlement	In February 2017, the PUCO approved a settlement agreement filed by OPCo in December 2016 which resolved all remaining open issues on remand from the Supreme Court of Ohio in OPCo's 2009 - 2011 and June 2012 - May 2015 ESP filings. It also resolved all open issues in OPCo's 2009, 2014 and 2015 SEET filings and 2009, 2012 and 2013 FAC Audits.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo, which defined the sharing of costs and benefits associated with their respective generation plants. This agreement was terminated January 1, 2014.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWh	Kilowatt-hour.
LPSC	Louisiana Public Service Commission.

Term	Meaning
MATS	Mercury and Air Toxics Standards.
MISO	Midwest Independent Transmission System Operator.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatt-hour.
NAAQS	National Ambient Air Quality Standards.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NO_2	Nitrogen dioxide.
NO_x	Nitrogen oxide.
NRC	Nuclear Regulatory Commission.
NSR	New Source Review.
OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.
Ohio Phase-in-Recovery Funding	Ohio Phase-in-Recovery Funding LLC, a wholly-owned subsidiary of OPCo and a consolidated variable interest entity formed for the purpose of issuing and servicing securitization bonds related to phase-in recovery property.
Oklaunion Power Station	A single unit coal-fired generation plant totaling 650 MW located in Vernon, Texas. The plant is jointly owned by AEP Texas, PSO and certain nonaffiliated entities.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefits.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third-party sales. AEPSC acts as the agent.
OSS	Off-system Sales.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PCA	Power Coordination Agreement among APCo, I&M, KPCo and WPCo.
PIRR	Phase-In Recovery Rider.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PPA	Purchase Power and Sale Agreement.
Price River	Rights and interests in certain coal reserves located in Carbon County, Utah.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Putnam	Rights and interests in certain coal reserves located in Putnam, Mason and Jackson Counties, West Virginia.
Racine	A generation plant consisting of two hydroelectric generating units totaling 47.5 MWs located in Racine, Ohio and owned by AGR.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants: AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.
Registrants	SEC registrants: AEP, AEP Texas, AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo.
REP	Texas Retail Electric Provider.

Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.

Term	Meaning
ROE	Return on Equity.
RPM	Reliability Pricing Model.
RSR	Retail Stability Rider.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity for AEP and SWEPCo.
SCR	Selective Catalytic Reduction, NO_x reduction technology at Rockport Plant.
SEC	U.S. Securities and Exchange Commission.
SEET	Significantly Excessive Earnings Test.
SIA	System Integration Agreement, effective June 15, 2000, as amended, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SIP	State Implementation Plan.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
State Transcos	AEPTCo’s seven wholly-owned, FERC regulated, transmission only electric utilities, each of which is geographically aligned with AEP existing utility operating companies.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the “Tax Cuts and Jobs Act” (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
TCC	Formerly AEP Texas Central Company, now a division of AEP Texas.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	Formerly AEP Texas North Company, now a division of AEP Texas.
Transition Funding	AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III LLC, wholly-owned subsidiaries of TCC and consolidated variable interest entities formed for the purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation.
Transource Energy	Transource Energy, LLC, a consolidated variable interest entity formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates.
Trent	Trent Wind Farm, a 154 MW wind electricity generation facility located between Abilene and Sweetwater in West Texas.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
UMWA	United Mine Workers of America.
UPA	Unit Power Agreement.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
Wind Catcher Project	Wind Catcher Energy Connection Project, a joint PSO and SWEPCo project that was cancelled in July 2018. The estimated $4.5 billion project included the acquisition of a wind generation facility, totaling approximately 2,000 MWs of wind generation, and the construction of a generation interconnection tie-line totaling approximately 350 miles.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

This report made by the Registrants contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in "Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations," but there are others throughout this document which may be identified by words such as "expect," "anticipate," "intend," "plan," "believe," "will," "should," "could," "would," "project," "continue" and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document are presented as of the date of this document. Except to the extent required by applicable law, management undertakes no obligation to update or revise any forward-looking statement. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- Changes in economic conditions, electric market demand and demographic patterns in AEP service territories.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability or cost of capital to finance new capital projects and refinance existing debt.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load and customer growth.
- Weather conditions, including storms and drought conditions, and the ability to recover significant storm restoration costs.
- The cost of fuel and its transportation, the creditworthiness and performance of fuel suppliers and transporters and the cost of storing and disposing of used fuel, including coal ash and spent nuclear fuel.
- Availability of necessary generation capacity, the performance of generation plants and the availability of fuel.
- The ability to recover fuel and other energy costs through regulated or competitive electric rates.
- The ability to build or acquire renewable generation, transmission lines and facilities (including the ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs.
- New legislation, litigation and government regulation, including oversight of nuclear generation, energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances that could impact the continued operation, cost recovery and/or profitability of generation plants and related assets.
- Evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions, including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance.
- Resolution of litigation.
- The ability to constrain operation and maintenance costs.
- Prices and demand for power generated and sold at wholesale.
- Changes in technology, particularly with respect to energy storage and new, developing, alternative or distributed sources of generation.
- The ability to recover through rates any remaining unrecovered investment in generation units that may be retired before the end of their previously projected useful lives.
- Volatility and changes in markets for capacity and electricity, coal and other energy-related commodities, particularly changes in the price of natural gas.
- Changes in utility regulation and the allocation of costs within regional transmission organizations, including ERCOT, PJM and SPP.
- Changes in the creditworthiness of the counterparties with contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of debt.
- The impact of volatility in the capital markets on the value of the investments held by the pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact of such volatility on future funding requirements.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.

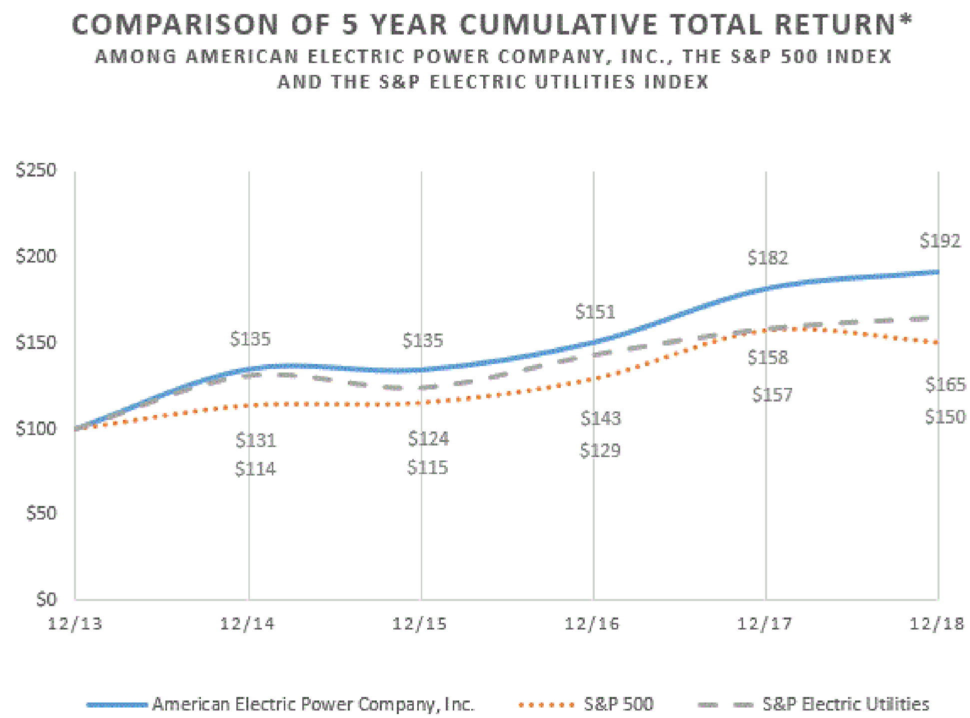
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, naturally occurring and human-caused fires, cyber security threats and other catastrophic events.

The forward-looking statements of the Registrants speak only as of the date of this report or as of the date they are made. The Registrants expressly disclaim any obligation to update any forward-looking information. For a more detailed discussion of these factors, see "Risk Factors" in Part I of this report.

Investors should note that the Registrants announce material financial information in SEC filings, press releases and public conference calls. Based on guidance from the SEC, the Registrants may use the Investors section of AEP's website (www.aep.com) to communicate with investors about the Registrants. It is possible that the financial and other information posted there could be deemed to be material information. The information on AEP's website is not part of this report.

AEP COMMON STOCK INFORMATION

AEP common stock is principally traded using the trading symbol "AEP" on the New York Stock Exchange. As of December 31, 2018, AEP had approximately 60,000 registered shareholders.



*$100 invested on 12/31/13 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SELECTED CONSOLIDATED FINANCIAL DATA

	2018 (a)	2017	2016	2015	2014
	(dollars in millions, except per share amounts)				
STATEMENTS OF INCOME DATA					
Total Revenues	$ 16,195.7	$ 15,424.9	$ 16,380.1	$ 16,453.2	$ 16,378.6
Operating Income (c)	$ 2,682.7	$ 3,525.0	$ 1,163.9	$ 3,292.4	$ 3,123.3
Income from Continuing Operations	$ 1,931.3	$ 1,928.9	$ 620.5	$ 1,768.6	$ 1,590.5
Income (Loss) From Discontinued Operations, Net of Tax	—	—	(2.5)	283.7	47.5
Net Income	1,931.3	1,928.9	618.0	2,052.3	1,638.0
Net Income Attributable to Noncontrolling Interests	7.5	16.3	7.1	5.2	4.2
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,923.8	$ 1,912.6	$ 610.9	$ 2,047.1	$ 1,633.8
BALANCE SHEETS DATA					
Total Property, Plant and Equipment	$ 73,085.2	$ 67,428.5	$ 62,036.6	$ 65,481.4	$ 63,605.9
Accumulated Depreciation and Amortization	17,986.1	17,167.0	16,397.3	19,348.2	19,970.8
Total Property, Plant and Equipment – Net	$ 55,099.1	$ 50,261.5	$ 45,639.3	$ 46,133.2	$ 43,635.1
Total Assets	$ 68,802.8	$ 64,729.1	$ 63,467.7	$ 61,683.1	$ 59,544.6
Total AEP Common Shareholders' Equity	$ 19,028.4	$ 18,287.0	$ 17,397.0	$ 17,891.7	$ 16,820.2
Noncontrolling Interests	$ 31.0	$ 26.6	$ 23.1	$ 13.2	$ 4.3
Long-term Debt (b)	$ 23,346.7	$ 21,173.3	$ 20,256.4	$ 19,572.7	$ 18,512.4
Obligations Under Capital Leases (b)	$ 289.0	$ 297.8	$ 305.5	$ 343.5	$ 362.8
AEP COMMON STOCK DATA					
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders:					
From Continuing Operations	$ 3.90	$ 3.89	$ 1.25	$ 3.59	$ 3.24
From Discontinued Operations	—	—	(0.01)	0.58	0.10
Total Basic Earnings per Share Attributable to AEP Common Shareholders	$ 3.90	$ 3.89	$ 1.24	$ 4.17	$ 3.34
Weighted Average Number of Basic Shares Outstanding (in millions)	492.8	491.8	491.5	490.3	488.6
Market Price Range:					
High	$ 81.05	$ 78.07	$ 71.32	$ 65.38	$ 63.22
Low	$ 62.71	$ 61.82	$ 56.75	$ 52.29	$ 45.80
Year-end Market Price	$ 74.74	$ 73.57	$ 62.96	$ 58.27	$ 60.72
Cash Dividends Declared per AEP Common Share	$ 2.53	$ 2.39	$ 2.27	$ 2.15	$ 2.03
Dividend Payout Ratio	64.87%	61.44%	183.06%	51.56%	60.78%
Book Value per AEP Common Share	$ 38.58	$ 37.17	$ 35.38	$ 36.44	$ 34.37

(a) The 2018 financial results include pretax asset impairments of $71 million. See Note 7 - Dispositions and Impairments for additional information.

(b) Includes portion due within one year.
(c) Amounts reflect the adoption of ASU 2017-07 "Compensation - Retirement Benefits." See Note 2 - New Accounting Pronouncements for additional information.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Company Overview

AEP is one of the largest investor-owned electric public utility holding companies in the United States. AEP's electric utility operating companies provide generation, transmission and distribution services to more than five million retail customers in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

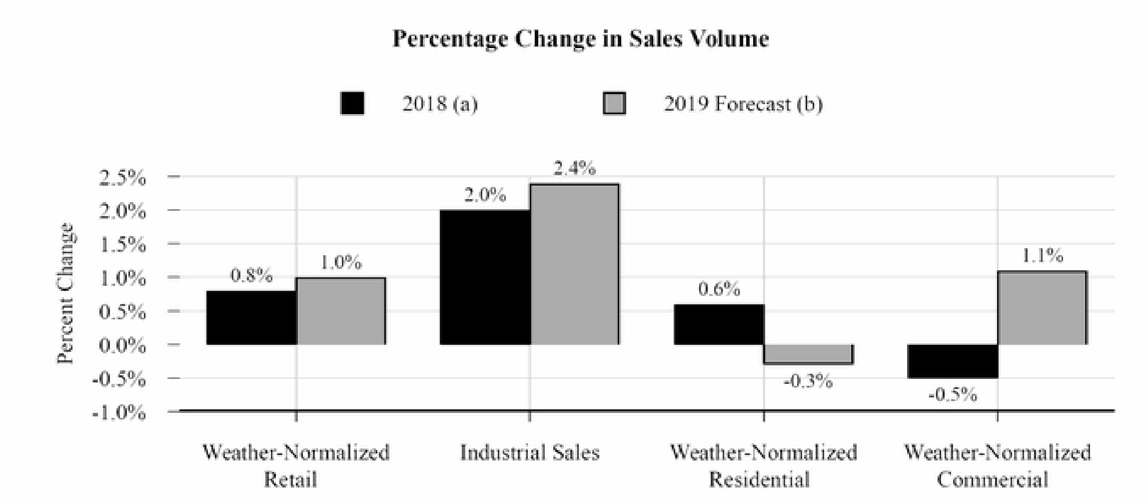
AEP's subsidiaries operate an extensive portfolio of assets including:

- Approximately 220,000 miles of distribution lines that deliver electricity to 5.4 million customers.
- Approximately 40,000 circuit miles of transmission lines, including approximately 2,200 circuit miles of 765 kV lines, the backbone of the electric interconnection grid in the Eastern United States.
- Approximately 23,000 megawatts of regulated owned generating capacity and approximately 4,900 megawatts of regulated PPA capacity in 3 RTOs as of December 31, 2018, one of the largest complements of generation in the United States.

Customer Demand

AEP's weather-normalized retail sales volumes for the year ended December 31, 2018 increased by 0.8% from the year ended December 31, 2017. AEP's 2018 industrial sales volumes increased 2% compared to 2017. The growth in industrial sales was spread across all operating companies and many industries. Weather-normalized residential sales increased 0.6% driven by strong growth in customer counts. Weather-normalized commercial sales decreased by 0.5% in 2018 compared to 2017.

In 2019, AEP anticipates weather-normalized retail sales volumes will increase by 1%. The industrial class is expected to increase by 2.4% in 2019, while weather-normalized residential sales volumes are projected to decrease by 0.3%. Weather-normalized commercial sales volumes are projected to increase by 1.1%.



(a) Percentage change for the year ended December 31, 2018 as compared to the year ended December 31, 2017.
(b) Forecasted percentage change for the year ended December 31, 2019 compared to the year ended December 31, 2018.

Regulatory Matters

AEP's public utility subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. Depending on the outcomes, these rate and regulatory proceedings can have a material impact on results of operations, cash flows and possibly financial condition. The following are key proceedings that AEP is currently involved in. See Note 4 - Rate Matters for additional information.

- *Hurricane Harvey and Texas Storm Cost Securitization* - In August 2017, Hurricane Harvey hit the coast of Texas, causing power outages in the AEP Texas service territory. In August 2018, AEP Texas filed a Determination of System Restoration Costs with the PUCT for total net storm costs, including storms previous to Hurricane Harvey, in the amount of $370 million. In November 2018, AEP Texas, the PUCT staff and intervenors filed a stipulation and settlement agreement with the PUCT that reduced the $370 million of total net storm costs to $354 million to reflect the impact of settlement agreement adjustments and additional insurance proceeds received. The net storm costs of $354 million are inclusive of a $152 million regulatory asset for deferred storm costs. AEP Texas is planning to make a filing in the first half of 2019 to request securitization of estimated distribution related assets of $247 million. The remaining $107 million of estimated transmission related assets is expected to be recovered through interim transmission filings or an upcoming base rate case.

- *Virginia Legislation Affecting Earnings Reviews* - In March 2018, Virginia enacted legislation requiring APCo to file its next generation and distribution base rate case by March 31, 2020 using 2017, 2018 and 2019 test years ("triennial review"). Triennial reviews are subject to an earnings test which provides that 70% of any earnings exceeding 70 basis points over the Virginia SCC authorized return on common equity would be refunded, or may be offset by capital expenditures in approved energy distribution grid transformation projects and/or new utility-owned solar and wind generation facilities. Management has reviewed APCo's actual and forecasted earnings for the triennial period and concluded that it is not probable but is reasonably possible that APCo will over-earn in Virginia during the 2017-2019 triennial period. Due to various uncertainties, including weather, storm restoration, weather-normalized demand and potential customer shopping during 2019, management cannot estimate a range of potential APCo Virginia over-earnings during the 2017-2019 triennial period.

- *Virginia Staff Depreciation Study Request* - In November 2018, Virginia staff recommended that APCo implement new Virginia jurisdictional depreciation rates effective January 1, 2018 based on APCo's depreciation study that was prepared at Virginia staff's request using December 31, 2017 APCo property balances. Implementation of those depreciation rates would result in a $21 million pretax increase in annual depreciation expense with no corresponding increase in retail base rates. In December 2018, APCo submitted a response to the Virginia Staff stating that it was inappropriate for APCo to change Virginia depreciation rates in advance of APCo's triennial review, citing the Virginia SCC's November 2014 order to not change APCo's Virginia depreciation rates until APCo's next base rate case/review.

- *2016 SEET Filing* - Ohio law provides for the return of significantly excessive earnings to ratepayers upon PUCO review. In 2016, OPCo recorded a 2016 SEET provision of $58 million based upon projected earnings data for companies in the comparable utilities risk group. In determining OPCo's return on equity in relation to the comparable utilities risk group, management excluded the following items resolved in OPCo's Global Settlement that was filed at the PUCO in December 2016 and subsequently approved in February 2017: (a) gain on the deferral of RSR costs, (b) refunds to customers related to the SEET remands and (c) refunds to customers related to fuel adjustment clause proceedings. In 2017, OPCo submitted its 2016 SEET filing with the PUCO in which management indicated that OPCo did not have significantly excessive earnings in 2016. In January 2018, PUCO staff filed testimony that OPCo did not have significantly excessive earnings in 2016. Also in January 2018, an intervenor filed testimony recommending a $53 million refund to customers related to OPCo 2016 SEET earnings. In February 2018, OPCo and PUCO staff filed a stipulation agreement in which both parties agreed that OPCo did not have significantly excessive earnings in 2016. A 2016 SEET hearing was held in April 2018 and management expects to receive an order in the first half of 2019. While management

believes that OPCo's adjusted 2016 earnings were not excessive, management did not adjust OPCo's 2016 SEET provision due to risks that the PUCO could rule against OPCo's proposed SEET adjustments, including treatment of the Global Settlement issues described above, adjust the comparable risk group or adopt a different 2016 SEET threshold.

- *2012 Texas Base Rate Case* - In 2012, SWEPCo filed a request with the PUCT to increase annual base rates primarily due to the completion of the Turk Plant. In 2013, the PUCT issued an order affirming the prudence of the Turk Plant. In July 2018, the Texas Third Court of Appeals reversed the PUCT's judgment affirming the prudence of the Turk Plant and remanded the issue back to the PUCT. In August 2018, SWEPCo filed a Motion for Reconsideration at the Court of Appeals, which was denied. In January 2019, SWEPCo and the PUCT filed petitions for review with the Texas Supreme Court. As of December 31, 2018, the net book value of Turk Plant was $1.5 billion, before cost of removal, including materials and supplies inventory and CWIP. If certain parts of the PUCT order are overturned and if SWEPCo cannot ultimately fully recover its approximate 33% Texas jurisdictional share of the Turk Plant investment, including AFUDC, it could reduce future net income and cash flows and impact financial condition.

- *FERC Transmission Complaint - AEP's PJM Participants* - In 2016, seven parties filed a complaint at the FERC that alleged the base return on common equity used by AEP's transmission owning subsidiaries within PJM in calculating formula transmission rates under the PJM OATT is excessive and should be reduced from 10.99% to 8.32%, effective upon the date of the complaint. In March 2018, AEP's transmission owning subsidiaries within PJM and six of the complainants filed a settlement agreement with the FERC (the seventh complainant abstained). If approved by the FERC, the settlement agreement establishes a base ROE for AEP's transmission owning subsidiaries within PJM of 9.85% (10.35% inclusive of the RTO incentive adder of 0.5%), effective January 1, 2018 and increases the cap on the equity portion of the capital structure to 55% from 50%. In April 2018, an ALJ accepted the interim settlement rates, which were implemented effective January 1, 2018. These interim rates are subject to refund or surcharge, with interest. In April 2018, certain intervenors filed comments at the FERC recommending a base ROE of 8.48% and a one-time refund of $184 million. The FERC trial staff filed comments recommending a base ROE of 8.41% and one-time refund of $175 million. Another intervenor recommended the refund be calculated in accordance with the base ROE that will ultimately be approved by the FERC. In May 2018, management filed reply comments providing further support for the 9.85% base ROE agreed to in the settlement agreement. In February 2019, the FERC issued an order that requested additional information in order to evaluate the settlement. That order did not rule on the merits of the settlement.

- *FERC Transmission Complaint - AEP's SPP Participants* - In 2017, several parties filed a complaint at the FERC that states the base return on common equity used by AEP's transmission owning subsidiaries within SPP in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.36%, effective upon the date of the complaint through September 5, 2018. In September 2018, the same parties filed another complaint at the FERC that states the base return on common equity used should be reduced from 10.7% to 8.71%, effective upon the date of the second complaint. A hearing at the FERC is scheduled for August 2019.

Utility Rates and Rate Proceedings

The Registrants file rate cases with their regulatory commissions seeking increases or decreases to their electric service rates to recover their costs and earn a fair return on their investments. The outcomes of these regulatory proceedings impact the Registrants' current and future results of operations, cash flows and financial position.

The following tables show the Registrants' completed and pending base rate case proceedings in 2018. See Note 4 - Rate Matters for additional information.

Completed Base Rate Case Proceedings

Company	Jurisdiction	Approved Revenue Requirement Increase (in millions)	Approved ROE	New Rates Effective
I&M	Indiana	$ 96.8	9.95%	July 2018
I&M	Michigan	49.9	9.9%	April 2018

Pending Base Rate Case Proceedings

Company	Jurisdiction	Filing Date	Requested Revenue Requirement Increase (in millions)	Requested ROE	Commission Staff/ Intervenor Range of Recommended ROE
APCo	West Virginia	May 2018	$ 80.2	10.22%	9.75%
PSO	Oklahoma	October 2018	88.4	10.3%	9% - 9.36%
WPCo	West Virginia	May 2018	15.1	10.22%	9.75%

Dolet Hills Lignite Company Operations

In November 2018, SWEPCo and CLECO announced that the Dolet Hills Power Station will change to a seasonal operational strategy. DHLC's mining operation will continue year-round but will reduce its lignite output. SWEPCo's share of the net investment in the Dolet Hills Power Station is $132 million and the maximum exposure of SWEPCo's total investment in DHLC is $190 million. Management will continue to monitor the economic viability of the Dolet Hills Power Station and DHLC.

Wind Catcher Project

In July 2017, PSO and SWEPCo submitted filings with the OCC, LPSC, APSC and PUCT requesting various regulatory approvals needed for the companies to proceed with the Wind Catcher Project. In July 2018, the PUCT denied SWEPCo's request for a Certificate of Public Convenience and Necessity to proceed with the Wind Catcher Project. PSO and SWEPCo subsequently cancelled the Wind Catcher Project. Total expenses incurred for the years ended December 31, 2018 and 2017 were $41 million and $14 million, respectively.

Other Renewable Generation

The growth of AEP's renewable generation portfolio reflects the company's strategy to diversify generation resources to provide clean energy options to customers that meet both their energy and capacity needs.

Contracted Renewable Generation Facilities

AEP continues to develop its renewable portfolio within the Generation & Marketing segment. Activities include working directly with wholesale and large retail customers to provide tailored solutions based upon market knowledge, technology innovations and deal structuring which may include distributed solar, wind, combined heat and power, energy storage, waste heat recovery, energy efficiency, peaking generation and other forms of cost reducing energy

technologies. The Generation & Marketing segment also develops and/or acquires large scale renewable generation projects that are backed with long-term contracts with creditworthy counterparties. As of December 31, 2018, subsidiaries within AEP's Generation & Marketing segment had approximately 436 MWs of contracted renewable generation projects in-service. In addition, as of December 31, 2018, these subsidiaries had approximately 57 MWs of renewable generation projects under construction with total estimated capital costs of $80 million related to these projects.

In January 2018, AEP admitted a nonaffiliate as a member of Desert Sky Wind Farm LLC and Trent Wind Farm LLC (collectively "the LLCs") to own and repower Desert Sky and Trent. The nonaffiliated member contributed full turbine sets to each project in exchange for a 20.1% interest in the LLCs. AEP has contributed its cash equity capital commitment of $235 million related to its 79.9% share of the LLCs, or 261 MWs. The wind farms were fully repowered and placed in-service in the third quarter of 2018. AEP is subject to a put and has a call option after certain conditions are met, either of which would liquidate the nonaffiliated member's interest. See Note 17 - Variable Interest Entities for additional information.

In December 2018, AEP signed a Purchase and Sale Agreement with a nonaffiliate to acquire a 75% interest in a 302 MW wind generation project located in West Texas upon completion. Management expects the transaction to close and the wind generation facility to be in-service in mid-2019.
In February 2019, AEP signed an agreement to purchase Sempra Renewables LLC and its 724 MWs of wind generation and battery assets for approximately $1.1 billion, subject to closing and working capital adjustments. As part of the purchase price, AEP will pay $551 million in cash and assume $343 million of existing project debt obligations of the non-consolidated joint ventures. Additionally, the acquisition will be accompanied by the recognition of non-controlling tax equity interest of $162 million associated with certain of the acquired wind farms. The wind generation portfolio includes seven wholly or jointly-owned wind farms with long-term PPAs for 100% of their energy production. The transaction is expected to close in mid-2019 and is subject to regulatory approvals from the FERC and federal clearance pursuant to the Hart-Scott-Rodino Antitrust Improvements Act of 1976.

Regulated Renewable Generation Facilities

In July 2017, APCo submitted filings with the Virginia SCC and the WVPSC requesting regulatory approval to acquire two wind generation facilities totaling approximately 225 MWs. In the second quarter of 2018, the Virginia SCC and WVPSC denied APCo's applications to acquire the two wind generation facilities.

In September 2018, OPCo, consistent with its commitment in the previously approved PPA application, submitted a filing with the PUCO demonstrating a need for up to 900 MWs of economically beneficial renewable resources in Ohio. This filing was followed by a separate filing for two solar Renewable Energy Purchase Agreements totaling 400 MWs. In January 2019, PUCO staff recommended that the PUCO reject OPCo's request. If approved, the solar generation facilities are expected to be operational by the end of 2021.

In January 2019, PSO and SWEPCo issued requests for proposals to acquire up to 1,000 MWs and 1,200 MWs of wind generation, respectively. The wind generation projects would be subject to regulatory approval and placed in-service by the end of 2021.

Federal Tax Reform

In December 2017, Tax Reform legislation was signed into law. Tax Reform includes significant changes to the Internal Revenue Code of 1986, as amended, including lowering the corporate federal income tax rate from 35% to 21%. As a result of this rate change, the Registrants' deferred tax assets and liabilities were remeasured using the newly enacted rate of 21% in December 2017. In response to Tax Reform, the SEC staff issued Staff Accounting Bulletin 118 (SAB 118) in December 2017. SAB 118 provided for up to a one year period (the measurement period) in which to complete the required analyses and accounting required by Tax Reform.

During 2017, AEP recorded provisional amounts for the income tax effects of Tax Reform. Throughout 2018, AEP continued to assess the impacts of legislative changes in the tax code as well as interpretative changes of the tax code. The measurement period adjustments recorded during 2018 were immaterial.

The measurement period under SAB 118 ended in December 2018. However, Tax Reform uncertainties still remain and AEP will continue to monitor income tax effects that may change as a result of future legislation and further interpretation of Tax Reform based on proposed U.S. Treasury regulations and guidance from the IRS and state tax authorities.

Status of Tax Reform Regulatory Proceedings

During 2018, state utility commissions issued orders and instructions requiring public utilities, including the Registrants, to provide the benefits of Tax Reform to customers. As of December 31, 2018, the Registrants have received orders and instructions from a majority of the jurisdictions in which they operate. The table below summarizes the various regulatory jurisdictions where the regulatory effects of Tax Reform proceedings have not been fully resolved. See Note 4 - Rate Matters for additional information.

Registrant (Jurisdiction)	Change in Tax Rate	Excess ADIT Subject to Normalization Requirements	Excess ADIT Not Subject to Normalization Requirements
AEP Texas (Texas-Distribution)	Order Issued	Order Issued	Order Issued – Partial (a)
AEP Texas (Texas-Transmission)	Order Issued	To be addressed in a later filing	To be addressed in a later filing
APCo (Virginia)	Legislation Enacted – Case Pending (b)	Legislation Enacted – Case Pending (b)	Order Issued – Partial; Separate Case Pending (c)
I&M (Michigan)	Order Issued	Case Pending	Case Pending
SWEPCo (Louisiana)	Case Pending – Rates Implemented (d)	Case Pending – Rates Implemented (d)	Case Pending – Rates Implemented (d)
SWEPCo (Texas)	Order Issued	To be addressed in a later filing	To be addressed in a later filing
PJM FERC Transmission	Settlement Approved (e)	Settlement Approved (e)	Settlement Approved (e)
SPP FERC Transmission	To be addressed in a later filing	To be addressed in a later filing	To be addressed in a later filing

(a) A portion of the Excess ADIT that is not subject to rate normalization requirements is to be addressed in a later filing.
(b) Legislation has been issued for a blanket amount that is subject to true-up and final commission approval.
(c) In October 2018, the Virginia SCC issued an order approving APCo's request to refund a portion of the Excess ADIT that is not subject to rate normalization requirements to customers. The remainder is to be addressed in a separate pending case.
(d) Rates have been implemented through a filed formula rate plan that is subject to true-up and final commission approval.
(e) An ALJ has approved a settlement. The settlement is subject to final FERC ruling.

Merchant Coal Generation Assets

In September 2018, management announced plans to close the Oklaunion Power Station by October 2020. In the fourth quarter of 2018, management announced plans to close Conesville Plant Units 5 and 6 in May 2019 and Unit 4 in May 2020. The closures are not expected to have a material impact on net income, cash flows or financial condition.

Racine

A project to reconstruct a defective dam structure at Racine began in the first quarter of 2017. In December 2017, an impairment analysis was triggered by an increase in the expected costs of the dam reconstruction activities, resulting in a pretax impairment charge equal to Racine's net book value of $43 million as of December 31, 2017.

Reconstruction activities at Racine continued through 2018. Due to a significant increase in estimated costs to complete the reconstruction project, in the third quarter of 2018, an impairment analysis was performed resulting in an additional impairment of $35 million, representing the total costs previously capitalized during 2018. During the fourth quarter of 2018, there were no significant increases in estimated costs to complete the reconstruction project and no other events were identified that would have triggered the need for an additional impairment analysis at Racine.

Reconstruction activities at Racine are estimated to be completed in the fourth quarter of 2019. AEP expects to incur additional capital expenditures to complete the reconstruction project, at which point the fair value of Racine, as fully operational, is expected to approximate the amount of those remaining estimated capital expenditures. Future revisions in cost estimates could result in additional losses which could reduce future net income and cash flows and impact financial condition.

Merchant Portion of Turk Plant

SWEPCo constructed the Turk Plant, a base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which was placed into service in December 2012 and is included in the Vertically Integrated Utilities segment. SWEPCo owns 73% (440 MWs) of the Turk Plant and operates the facility.

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the SWEPCo Arkansas jurisdictional share of the Turk Plant (approximately 20%). Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. In June 2010, in response to an Arkansas Supreme Court decision, the APSC issued an order which reversed and set aside the previously granted CECPN. This share of the Turk Plant output is currently not subject to cost-based rate recovery and is being sold into the wholesale market. Approximately 80% of the Turk Plant investment is recovered under cost-based rate recovery in Texas, Louisiana and through SWEPCo's wholesale customers under FERC-based rates. As of December 31, 2018, the net book value of Turk Plant was $1.5 billion, before cost of removal, including materials and supplies inventory and CWIP. If SWEPCo cannot ultimately recover its investment and expenses related to the Turk Plant, it could reduce future net income and cash flows and impact financial condition.

LITIGATION

In the ordinary course of business, AEP is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. Management assesses the probability of loss for each contingency and accrues a liability for cases that have a probable likelihood of loss if the loss can be estimated. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition. See Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies for additional information.

Rockport Plant Litigation

In July 2013, the Wilmington Trust Company filed a complaint in the U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it would be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering, refueling or retirement of the unit. The plaintiffs seek a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiffs. The New York court granted a motion to transfer this case to the U.S. District Court for the Southern District of Ohio.

AEGCo and I&M sought and were granted dismissal of certain of the plaintiffs' claims, including claims for compensatory damages, breach of contract, breach of the implied covenant of good faith and fair dealing and indemnification of costs. Plaintiffs voluntarily dismissed the surviving claims that AEGCo and I&M failed to exercise prudent utility practices with prejudice, and the court issued a final judgment. The plaintiffs subsequently filed an appeal in the U.S. Court of Appeals for the Sixth Circuit.

The U.S. Court of Appeals for the Sixth Circuit issued an opinion and judgment affirming the district court's dismissal of the owners' breach of good faith and fair dealing claim as duplicative of the breach of contract claims, reversing the district court's dismissal of the breach of contract claims and remanding the case for further proceedings.

In July 2017, AEP filed a motion with the U.S. District Court for the Southern District of Ohio in the original NSR litigation, seeking to modify the consent decree to eliminate the obligation to install certain future controls at Rockport Plant, Unit 2 if AEP does not acquire ownership of that Unit, and to modify the consent decree in other respects to preserve the environmental benefits of the consent decree. Responsive and supplemental filings have been made by all parties. In November 2017, the district court granted the owners' unopposed motion to stay the lease litigation to afford time for resolution of AEP's motion to modify the consent decree. In September 2018, the district court granted AEP's unopposed motion to stay further proceedings regarding the consent decree to facilitate settlement discussions among the parties to the consent decree. See "Proposed Modification of the NSR Litigation Consent Decree" section below for additional information.

Management will continue to defend against the claims. Given that the district court dismissed plaintiffs' claims seeking compensatory relief as premature, and that plaintiffs have yet to present a methodology for determining or any analysis supporting any alleged damages, management is unable to determine a range of potential losses that are reasonably possible of occurring.

ENVIRONMENTAL ISSUES

AEP has a substantial capital investment program and incurs additional operational costs to comply with environmental control requirements. Additional investments and operational changes will need to be made in response to existing and anticipated requirements such as new CAA requirements to reduce emissions from fossil fuel-fired power plants, rules governing the beneficial use and disposal of coal combustion by-products, clean water rules and renewal permits for certain water discharges.

AEP is engaged in litigation about environmental issues, was notified of potential responsibility for the clean-up of contaminated sites and incurred costs for disposal of SNF and future decommissioning of the nuclear units. AEP, along with various industry groups, affected states and other parties challenged some of the Federal EPA requirements in court. Management is also engaged in the development of possible future requirements including the items discussed below. Management believes that further analysis and better coordination of these environmental requirements would facilitate planning and lower overall compliance costs while achieving the same environmental goals.

AEP will seek recovery of expenditures for pollution control technologies and associated costs from customers through rates in regulated jurisdictions. Environmental rules could result in accelerated depreciation, impairment of assets or regulatory disallowances. If AEP is unable to recover the costs of environmental compliance, it would reduce future net income and cash flows and impact financial condition.

Environmental Controls Impact on the Generating Fleet

The rules and proposed environmental controls discussed below will have a material impact on the generating units in the AEP System. Management continues to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of December 31, 2018, the AEP System had a total generating capacity of approximately 25,400 MWs, of which approximately 13,200 MWs were coal-fired. Management continues to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on the fossil generating facilities. Based upon management estimates, AEP's investment to meet these existing and proposed requirements ranges from approximately $650 million to $1.5 billion through 2025.

The cost estimates will change depending on the timing of implementation and whether the Federal EPA provides flexibility in finalizing proposed rules or revising certain existing requirements. The cost estimates will also change based on: (a) the states' implementation of these regulatory programs, including the potential for SIPs or FIPs that impose more stringent standards, (b) additional rulemaking activities in response to court decisions, (c) the actual performance of the pollution control technologies installed on the units, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired and replaced, including the type and amount of such replacement capacity, (g) the outcome of the pending motion to modify the NSR consent decree and (h) other factors. In addition, management is continuing to evaluate the economic feasibility of environmental investments on both regulated and competitive plants.

The table below represents the net book value before cost of removal, including related materials and supplies inventory, of plants or units of plants previously retired that have a remaining net book value as of December 31, 2018.

Company	Plant Name and Unit	Generating Capacity (in MWs)	Amounts Pending Regulatory Approval (in millions)
APCo	Kanawha River Plant	400	$ 44.8
APCo	Clinch River Plant, Unit 3	235	32.5
APCo (a)	Clinch River Plant, Units 1 and 2	470	26.7
APCo	Sporn Plant, Units 1 and 3	300	17.2
APCo	Glen Lyn Plant	335	14.2
SWEPCo	Welsh Plant, Unit 2	528	50.6
Total		2,268	$ 186.0

(a) APCo obtained permits following the Virginia SCC's and WVPSC's approval to convert Clinch River Plant, Units 1 and 2 to natural gas. In 2015, APCo retired the coal-related assets of Clinch River Plant, Units 1 and 2. Clinch River Plant, Unit 1 and Unit 2 began operations as natural gas units in 2016.

Management is seeking or will seek recovery of the remaining net book value in future rate proceedings. To the extent the net book value of these generation assets is not recoverable, it could materially reduce future net income and cash flows and impact financial condition.

Proposed Modification of the New Source Review Litigation Consent Decree

In 2007, the U.S. District Court for the Southern District of Ohio approved a consent decree between AEP subsidiaries in the eastern area of the AEP System and the Department of Justice, the Federal EPA, eight northeastern states and other interested parties to settle claims that the AEP subsidiaries violated the NSR provisions of the CAA when they undertook various equipment repair and replacement projects over a period of nearly 20 years. The consent decree's terms include installation of environmental control equipment on certain generating units, a declining cap on SO_2 and NO_x emissions from the AEP System and various mitigation projects.

In July 2017, AEP filed a motion with the U.S. District Court for the Southern District of Ohio seeking to modify the consent decree to eliminate an obligation to install future controls at Rockport Plant, Unit 2 if AEP does not acquire ownership of that unit, and to modify the consent decree in other respects to preserve the environmental benefits of the consent decree. The other parties to the consent decree opposed AEP's motion. The district court granted AEP's request to delay the deadline to install SCR technology at Rockport Plant, Unit 2 until June 2020.

In January 2018, AEP filed a supplemental motion proposing to install the SCR at Rockport Plant, Unit 2 and achieve the final SO_2 emission cap applicable to the plant under the consent decree by the end of 2020 and later filed a detailed statement of the specific relief requested to address the changed circumstances at Rockport Plant, Unit 2. In September 2018, the district court granted AEP's unopposed motion to stay further proceedings on the pending motion to modify the consent decree to facilitate settlement discussions among the parties.

AEP is seeking to modify the consent decree as a means to resolve or substantially narrow the issues in pending litigation with the owners of Rockport Plant, Unit 2. See "Rockport Plant Litigation" section above and Note 6 - Commitments, Guarantees and Contingencies for additional information.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements. The primary regulatory programs that continue to drive investments in AEP's existing generating units include: (a) periodic revisions to NAAQS and the development of SIPs to achieve any more stringent standards, (b) implementation of the regional haze program by the states and the Federal EPA, (c) regulation of hazardous

air pollutant emissions under MATS, (d) implementation and review of CSAPR, a FIP designed to eliminate significant contributions from sources in upwind states to non-attainment or maintenance areas in downwind states and (e) the Federal EPA's regulation of greenhouse gas emissions from fossil fueled electric generating units under Section 111 of the CAA.

In March 2017, President Trump issued a series of executive orders designed to allow the Federal EPA to review and take appropriate action to revise or rescind regulatory requirements that place undue burdens on affected entities, including specific orders directing the Federal EPA to review rules that unnecessarily burden the production and use of energy. Future changes that result from this effort may affect AEP's compliance plans.

Notable developments in significant CAA regulatory requirements affecting AEP's operations are discussed in the following sections.

National Ambient Air Quality Standards

The Federal EPA issued new, more stringent NAAQS for SO_2 in 2010, PM in 2012 and ozone in 2015; the existing standards for NO_2 were retained after review by the Federal EPA in 2018. Implementation of these standards is underway. In December 2017, the Federal EPA published final designations for certain areas' compliance with the 2010 SO_2 NAAQS. Additional designations will be made in 2020. States may develop additional requirements for AEP's facilities as a result of these designations. In June 2018, the Federal EPA proposed to retain the current primary standard for SO_2 of 75 parts per billion, without change.

In December 2016, the Federal EPA completed an integrated review plan for the 2012 PM standard. Work is currently underway on scientific, risk and policy assessments necessary to develop a proposed rule, which is anticipated in 2021.

Most areas of the country were designated attainment or unclassifiable for the 2015 ozone standard in November 2017. The Federal EPA finalized non-attainment designations for the remaining areas in 2018. The Federal EPA has also issued information to assist the states in developing plans that address their obligations under the interstate transport provisions of the CAA for the 2008 and 2015 ozone standards. The Federal EPA has confirmed that for states included in the CSAPR program, there are no additional interstate transport obligations, as all areas of the country are expected to attain the 2008 ozone standard before 2023. State implementation plans for the 2015 ozone standard were submitted in October 2018. Challenges to the 2015 ozone standard are pending in the U.S. Court of Appeals for the District of Columbia Circuit. In November 2018, the Federal EPA proposed final requirements for implementing the 2015 ozone standard. Management cannot currently predict the nature, stringency or timing of additional requirements for AEP's facilities based on the outcome of these activities.

Regional Haze

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how the CAA's requirement that certain facilities install best available retrofit technology (BART) would address regional haze in federal parks and other protected areas. BART requirements apply to power plants. CAVR will be implemented through SIPs or, if SIPs are not adequate or are not developed on schedule, through FIPs. In January 2017, the Federal EPA revised the rules governing submission of SIPs to implement the visibility programs, including a provision that postpones the due date for the next comprehensive SIP revisions until 2021. Petitions for review of the final rule revisions have been filed in the U.S. Court of Appeals for the District of Columbia Circuit.

In March 2012, the Federal EPA proposed disapproval of a portion of the regional haze SIP in Arkansas and finalized a FIP in September of 2016. The FIP includes revised BART determinations for the Flint Creek Plant that are consistent with the environmental controls installed to address other CAA requirements. The final rule is being challenged in the U.S. Court of Appeals for the Eighth Circuit, but has been held in abeyance to allow the parties to engage in settlement negotiations. Arkansas issued a proposed SIP revision to allow sources to participate in the CSAPR ozone season program in lieu of the source-specific NO_x BART requirements in the FIP, and the Federal EPA approved the revision. Arkansas finalized a separate action to revise the SO_2 BART determinations which was challenged before the Arkansas

Pollution Control and Ecology Commission. The ALJ has recommended that the challenge be dismissed. The Federal EPA proposed to approve the Arkansas SO_2 BART determinations, which if the Federal EPA issues final approval, no further emission reductions will be required at the Flint Creek Plant.

The Federal EPA also disapproved portions of the Texas regional haze SIP. In January 2017, the Federal EPA proposed source-specific BART requirements for SO_2 from sources in Texas, including Welsh Plant, Unit 1. The proposed source-specific approach for Welsh Plant, Unit 1 called for installation of a wet FGD system. In October 2017, the Federal EPA finalized a FIP that allows participation in the CSAPR ozone season program to satisfy the NO_x regional haze obligations for electric generating units in Texas. Additionally, the Federal EPA finalized an intrastate SO_2 emissions trading program based on CSAPR allowance allocations as an alternative to source-specific SO_2 requirements. The opportunity to use emissions trading to satisfy the regional haze requirements for NO_x and SO_2 at AEP's affected generating units provides greater flexibility and lower cost compliance options than the original proposal. A challenge to the FIP has been filed in the U.S. Court of Appeals for the Fifth Circuit by various intervenors and the case has been held in abeyance pending the Federal EPA's reconsideration of the final rule. In August 2018, the Federal EPA proposed to affirm its October 2017 FIP approval and requested comment on certain aspects of the FIP promulgation and specifically on the intrastate SO_2 trading program. Management supports the intrastate trading program contained in the FIP as a compliance alternative to source-specific controls.

In June 2012, the Federal EPA published revisions to the regional haze rules to allow states participating in the CSAPR trading programs to use those programs in place of source-specific BART for SO_2 and NO_x emissions based on its determination that CSAPR results in greater visibility improvements than source-specific BART in the CSAPR states. The rule was challenged in the U.S. Court of Appeals for the District of Columbia Circuit. In March 2018, the U.S. Court of Appeals for the District of Columbia Circuit affirmed the Federal EPA rule that found that CSAPR provides greater visibility improvements than BART. Challenges to the changes made to the scope of the program in 2016 are being held in abeyance while the Federal EPA reconsiders the Texas SO_2 BART FIP.

Cross-State Air Pollution Rule

In 2011, the Federal EPA issued CSAPR as a replacement for the Clean Air Interstate Rule, a regional trading program designed to address interstate transport of emissions that contributed significantly to downwind non-attainment with the 1997 ozone and PM NAAQS. CSAPR relies on newly-created SO_2 and NO_x allowances and individual state budgets to compel further emission reductions from electric utility generating units. Interstate trading of allowances is allowed on a restricted sub-regional basis.

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the U.S. Court of Appeals for the District of Columbia Circuit. The rule was vacated, but that decision was reversed on appeal to the U.S. Supreme Court. On remand, the U.S. Court of Appeals for the District of Columbia Circuit allowed Phase I of CSAPR to take effect on January 1, 2015 and Phase II to take effect on January 1, 2017. In July 2015, the court found that the Federal EPA over-controlled the SO_2 and/or NO_x budgets of 14 states. The court remanded the rule to the Federal EPA for revision consistent with the court's opinion while CSAPR remained in place.

In October 2016, the Federal EPA issued a final rule to address the remand and to incorporate additional changes necessary to address the 2008 ozone standard. The final rule significantly reduced ozone season budgets in many states and discounted the value of banked CSAPR ozone season allowances beginning with the 2017 ozone season. The rule has been challenged in the courts and petitions for administrative reconsideration have been filed. Management has been complying with the more stringent ozone season budgets while these petitions were pending.

Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

In 2012, the Federal EPA issued a rule addressing a broad range of HAPs from coal and oil-fired power plants. The rule established unit-specific emission rates for units burning coal on a 30-day rolling average basis for mercury, PM (as a surrogate for particles of non-mercury metals) and hydrogen chloride (as a surrogate for acid gases). In addition, the rule proposed work practice standards, such as boiler tune-ups, for controlling emissions of organic HAPs and dioxin/furans. Compliance was required within three years. Management obtained administrative extensions for up to one year at several units to facilitate the installation of controls or to avoid a serious reliability problem.

In 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied all of the petitions for review of the 2012 final rule. Industry trade groups and several states filed petitions for further review in the U.S. Supreme Court.

In June 2015, the U.S. Supreme Court reversed the decision of the U.S. Court of Appeals for the District of Columbia Circuit. The court remanded the MATS rule to the Federal EPA to consider costs in determining whether to regulate emissions of HAPs from power plants. The Federal EPA issued a supplemental finding concluding that, after considering the costs of compliance, it was appropriate and necessary to regulate HAP emissions from coal and oil-fired units. Petitions for review of the Federal EPA's determination were filed in the U.S. Court of Appeals for the District of Columbia Circuit. Oral argument was scheduled for May 2017, but in April 2017, the Federal EPA requested that oral argument be postponed to facilitate its review of the rule, which remains in effect. In December 2018, the Federal EPA released a proposed finding that the costs of reducing HAP emissions to the level in the current rule exceed the benefits of those HAP emission reductions. The Federal EPA also determined that there are no significant changes in control technologies and the remaining risks associated with HAP emissions do not justify any more stringent standards. However, the Federal EPA also proposed that it would not remove the source category or alter MATS and no further reductions are necessary. The comment period on this proposed finding has not yet commenced.

Climate Change, CO_2 Regulation and Energy Policy

In October 2015, the Federal EPA published the final CO_2 emissions standards for new, modified and reconstructed fossil fuel-fired steam generating units and combustion turbines, and final guidelines for the development of state plans to regulate CO_2 emissions from existing sources, known as the Clean Power Plan (CPP).

The final rules are being challenged in the courts. In February 2016, the U.S. Supreme Court issued a stay on the final CPP, including all of the deadlines for submission of initial or final state plans. The stay will remain in effect until a final decision is issued by the U.S. Court of Appeals for the District of Columbia Circuit and the U.S. Supreme Court considers any petition for review. In March 2017, the President issued an Executive Order directing the Federal EPA to reconsider the CPP and the associated standards for new sources. The Federal EPA filed a motion to hold the challenges to the CPP in abeyance, and the cases are still pending.

In October 2017, the Federal EPA issued a proposed rule repealing the CPP. In December 2017, the Federal EPA issued an advanced notice of proposed rulemaking seeking information that should be considered by the Federal EPA in developing revised guidelines for state programs. In August 2018, the Federal EPA proposed the Affordable Clean Energy (ACE) rule to replace the CPP with new emission guidelines for regulating CO_2 from existing sources. ACE would establish a framework for states to adopt standards of performance for utility boilers based on heat rate improvements for such boilers. Comments were accepted until the end of October 2018. In December 2018, the Federal EPA filed a proposed rule revising the standards for new sources and determined that partial carbon capture and storage is not the best system of emission reduction because it is not available throughout the U.S. and is not cost-effective. Management is actively monitoring rulemaking activities.

AEP has taken action to reduce and offset CO_2 emissions from its generating fleet and expects CO_2 emissions from its operations to continue to decline due to the retirement of some of its coal-fired generation units, and actions taken to diversify the generation fleet and increase energy efficiency where there is regulatory support for such activities. The majority of the states where AEP has generating facilities passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements that can assist in reducing carbon emissions. Management is taking steps to comply with these requirements, including increasing wind and solar installations, power purchases and broadening AEP System's portfolio of energy efficiency programs.

In 2018, AEP announced new intermediate and long-term CO_2 emission reduction goals, based on the output of the company's integrated resource plans, which take into account economics, customer demand, grid reliability and resiliency, regulations and the company's current business strategy. The intermediate goal is a 60% reduction from 2000 CO_2 emission levels from AEP generating facilities by 2030; the long-term goal is an 80% reduction of CO_2 emissions from AEP generating facilities from 2000 levels by 2050. AEP's total estimated CO_2 emissions in 2018 were approximately 69 million metric tons, a 59% reduction from AEP's 2000 CO_2 emissions of approximately 167 million metric tons.

Federal and state legislation or regulations that mandate limits on the emission of CO_2 could result in significant increases in capital expenditures and operating costs, which in turn, could lead to increased liquidity needs and higher financing costs. Excessive costs to comply with future legislation or regulations might force AEP to close some coal-fired facilities, which could possibly lead to impairment of assets.

Coal Combustion Residual Rule

In April 2015, the Federal EPA published a final rule to regulate the disposal and beneficial re-use of coal combustion residuals (CCR), including fly ash and bottom ash generated at coal-fired electric generating units and also FGD gypsum generated at some coal-fired plants. The rule applies to new and existing active CCR landfills and CCR surface impoundments at operating electric utility or independent power production facilities. The rule imposes construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria and additional groundwater monitoring requirements to be implemented on a schedule spanning an approximate four-year implementation period. Certain records must be posted to a publicly available internet site. Initial groundwater monitoring reports were posted in the first quarter of 2018, and some of AEP's facilities were required to begin assessment monitoring programs to determine if unacceptable groundwater impacts will trigger future remedial actions. Additional groundwater data has been collected and further studies to design and assess appropriate remedial measures will be undertaken at four facilities in accordance with the rule.

The final 2015 rule has been challenged in the courts. In August 2018, the U.S. Court of Appeals for the District of Columbia Circuit issued its decision vacating and remanding certain provisions of the 2015 rule. Remaining issues were dismissed. None of the parties filed a motion for rehearing. The provisions addressed by the court's decision, including changes to the provisions for unlined impoundments and legacy sites, will be the subject of further rulemaking consistent with the court's decision.

In September 2017, the Federal EPA granted industry petitions to reconsider the CCR rule. In March 2018, the Federal EPA issued a proposed rule to modify certain provisions of the solid waste management standards and provide additional flexibility to facilities regulated under approved state programs. A final rule was signed in July 2018 that modifies certain compliance deadlines and other requirements in the rule. Additional changes to the minimum performance standards that were contained in the March proposed rule, and changes to respond to the decision of the U.S. Court of Appeals for the District of Columbia Circuit will be addressed in future rulemakings. In December 2018, challengers filed a motion for partial stay or vacatur of the July 2018 rule. On the same day, the Federal EPA filed a motion for remand of the July 2018 rule. Vacatur of the July 2018 rule could result in significant increases in capital expenditures and operating costs. Management is monitoring these developments and supports the adoption of more flexible compliance alternatives subject to the Federal EPA or state oversight.

Other utilities and industrial sources have been engaged in litigation with environmental advocacy groups who claim that releases of contaminants from wells, CCR units, pipelines and other facilities to ground waters that have a hydrologic connection to a surface water body represent an "unpermitted discharge" under the CWA. The Federal EPA has opened a rulemaking docket to solicit information to determine whether it should provide additional clarification of the scope of CWA permitting requirements for discharges to ground water. Management is unable to predict the outcome of these cases or the Federal EPA's rulemaking, which could impose significant additional costs on AEP's facilities.

Because AEP currently uses surface impoundments and landfills to manage CCR materials at generating facilities, significant costs will be incurred to upgrade or close and replace these existing facilities and conduct any required remedial actions. Closure and post-closure costs have been included in ARO in accordance with the requirements in the final rule. This estimate does not include costs of groundwater remediation, if required. Management will continue to evaluate the rule's impact on operations.

Clean Water Act Regulations

In 2014, the Federal EPA issued a final rule setting forth standards for existing power plants that is intended to reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. Compliance timeframes are established by the permit agency through each facility's National Pollutant Discharge Elimination System permit as those permits are renewed and have been incorporated into permits at several AEP facilities. Petitions for review were filed by industry and environmental groups in the U.S. Court of Appeals for the Second Circuit. The court denied the petitions and upheld the final rule. AEP's facilities are reviewing these requirements as their waste water discharge permits are renewed and making appropriate adjustments to their intake structures.

In November 2015, the Federal EPA issued a final rule revising effluent limitation guidelines for electricity generating facilities. The rule establishes limits on FGD wastewater, fly ash and bottom ash transport water and flue gas mercury control wastewater to be imposed as soon as possible after November 2018 and no later than December 2023. These requirements would be implemented through each facility's wastewater discharge permit. The rule has been challenged in the U.S. Court of Appeals for the Fifth Circuit. In March 2017, industry associations filed a petition for reconsideration of the rule with the Federal EPA. A final rule revising the compliance deadlines for FGD wastewater and bottom ash transport water to be no earlier than 2020 was issued in September 2017, but has been challenged in the courts. Management continues to assess technology additions and retrofits to comply with the rule and the impacts of the Federal EPA's recent actions on facilities' wastewater discharge permitting. Management is actively participating in the reconsideration proceedings.

In June 2015, the Federal EPA and the U.S. Army Corps of Engineers jointly issued a final rule to clarify the scope of the regulatory definition of "waters of the United States" in light of recent U.S. Supreme Court cases. The final rule was challenged in both courts of appeal and district courts. In January 2018, the U.S. Supreme Court ruled that challenges to the definition of "waters of the United States" must be filed in federal district courts. Challenges to the rule are proceeding, and courts have reached different conclusions about whether the 2015 rule should be implemented, or whether action to delay the implementation date to 2020 was valid. In December 2018, the Federal EPA and the U.S. Army Corps of Engineers released a proposed rule revising the definition, which would replace the definition in the 2015 rule and could significantly alter the scope of certain CWA programs. The comment period for this proposal has not yet commenced.

RESULTS OF OPERATIONS

SEGMENTS

AEP's primary business is the generation, transmission and distribution of electricity. Within its Vertically Integrated Utilities segment, AEP centrally dispatches generation assets and manages its overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

AEP's reportable segments and their related business activities are outlined below:

Vertically Integrated Utilities

- Generation, transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEGCo, APCo, I&M, KGPCo, KPCo, PSO, SWEPCo and WPCo.

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEP Texas and OPCo.
- OPCo purchases energy and capacity at auction to serve SSO customers and provides transmission and distribution services for all connected load.

AEP Transmission Holdco

- Development, construction and operation of transmission facilities through investments in AEPTCo. These investments have FERC-approved returns on equity.
- Development, construction and operation of transmission facilities through investments in AEP's transmission-only joint ventures. These investments have PUCT-approved or FERC-approved returns on equity.

Generation & Marketing

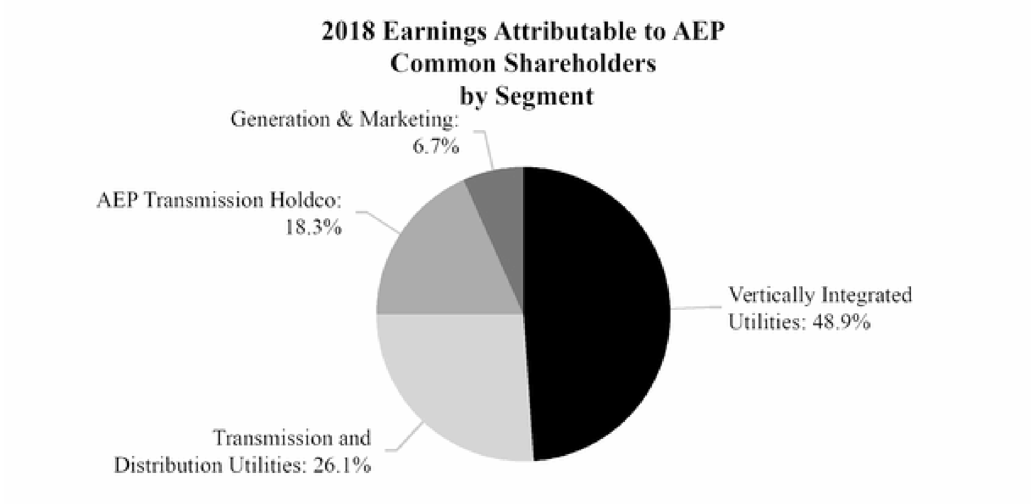
- Competitive generation in ERCOT and PJM.
- Marketing, risk management and retail activities in ERCOT, PJM, SPP and MISO.
- Contracted renewable energy investments and management services.

The remainder of AEP's activities are presented as Corporate and Other. While not considered a reportable segment, Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries, Parent's guarantee revenue received from affiliates, investment income, interest income, interest expense, income tax expense and other nonallocated costs.

The following discussion of AEP's results of operations by operating segment includes an analysis of Gross Margin, which is a non-GAAP financial measure. Gross Margin includes Total Revenues less the costs of Fuel and Other Consumables Used for Electric Generation as well as Purchased Electricity for Resale, Generation Deferrals and Amortization of Generation Deferrals as presented in the Registrants' statements of income as applicable. Under the various state utility rate making processes, these expenses are generally reimbursable directly from and billed to customers. As a result, they do not typically impact Operating Income or Earnings Attributable to AEP Common Shareholders. Management believes that Gross Margin provides a useful measure for investors and other financial statement users to analyze AEP's financial performance in that it excludes the effect on Total Revenues caused by volatility in these expenses. Operating Income, which is presented in accordance with GAAP in AEP's statements of income, is the most directly comparable GAAP financial measure to the presentation of Gross Margin. AEP's definition of Gross Margin may not be directly comparable to similarly titled financial measures used by other companies.

The following table presents Earnings (Loss) Attributable to AEP Common Shareholders by segment:

	Years Ended December 31,		
	2018	2017	2016
	(in millions)		
Vertically Integrated Utilities	$ 990.5	$ 790.5	$ 979.9
Transmission and Distribution Utilities	527.4	636.4	482.1
AEP Transmission Holdco	369.9	352.1	266.3
Generation & Marketing	135.3	166.0	(1,198.0)
Corporate and Other	(99.3)	(32.4)	80.6
Earnings Attributable to AEP Common Shareholders	$ 1,923.8	$ 1,912.6	$ 610.9



Note: 2018 Earnings Attributable to AEP Common Shareholders by Segment excludes Corporate and Other which is not considered a reportable segment.

AEP CONSOLIDATED

2018 Compared to 2017

Earnings Attributable to AEP Common Shareholders increased $11 million from $1.91 billion in 2017 to $1.92 billion in 2018 primarily due to:

- An increase in weather-related usage.
- Recovery of incremental utility plant investment through favorable rate proceedings in AEP's various jurisdictions.

These increases were partially offset by:

- An increase in other operation and maintenance expenses primarily within the Vertically Integrated Utilities and Transmission and Distribution Utilities segments.
- An increase in depreciation and amortization expenses primarily due to a higher depreciable base and approved increased depreciation rates in AEP's various jurisdictions.
- A decrease in earnings in the Generation & Marketing segment primarily due to the 2017 gain resulting from the sale of certain merchant generation assets.

2017 Compared to 2016

Earnings Attributable to AEP Common Shareholders increased from $611 million in 2016 to $1.91 billion in 2017 primarily due to:

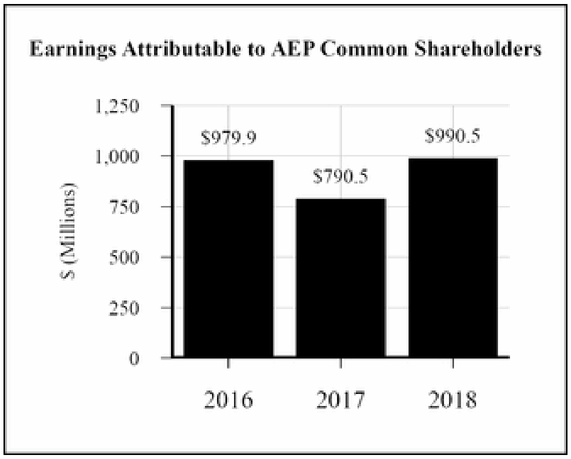
- An increase due to the impairment of certain merchant generation assets in 2016.
- An increase due to the gain on the sale of certain merchant generation assets in 2017.
- An increase in transmission investment primarily at AEP Transmission Holdco which resulted in higher revenues and income.
- Favorable rate proceedings in AEP's various jurisdictions.

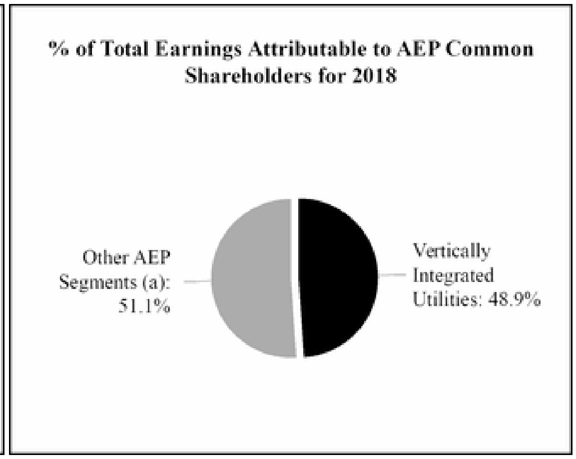
These increases were partially offset by:

- A decrease in generation revenues associated with the sale of certain merchant generation assets.
- A decrease in weather-related usage.
- A decrease in FERC wholesale municipal and cooperative revenues.
- The prior year reversal of income tax expense for an unrealized capital loss valuation allowance. AEP effectively settled a 2011 audit issue with the IRS resulting in a change in the valuation allowance.

AEP's results of operations by reportable segment are discussed below.

VERTICALLY INTEGRATED UTILITIES





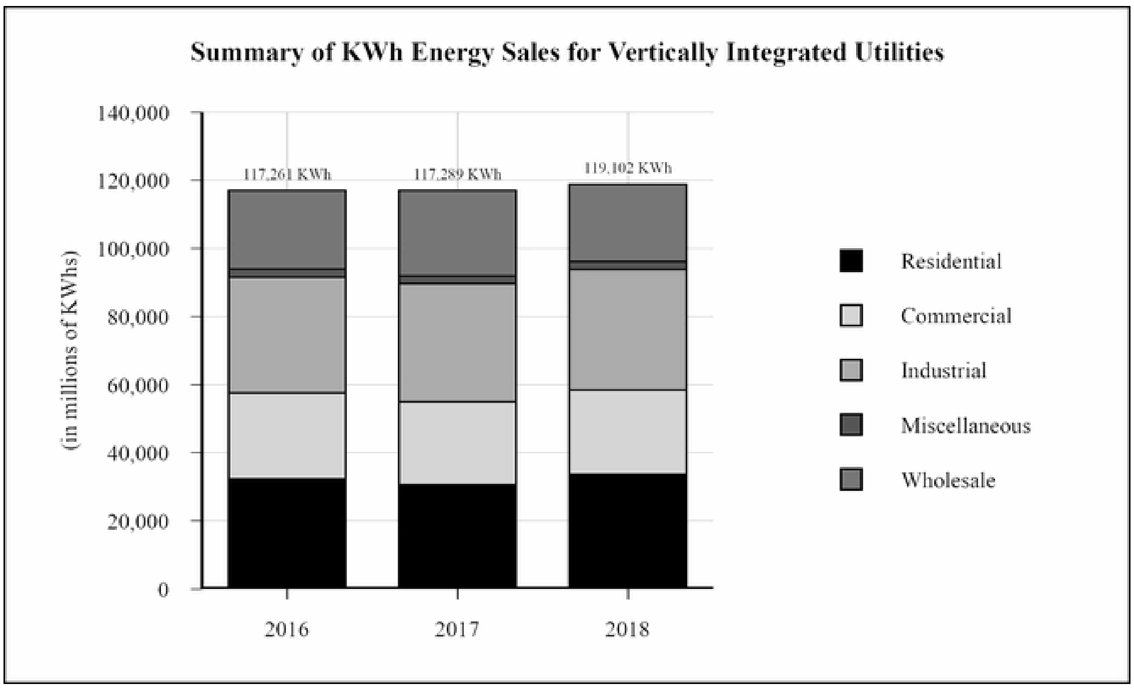
(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment.

Vertically Integrated Utilities	2018	2017	2016
	Years Ended December 31, (in millions)		
Revenues	$ 9,645.5	$ 9,192.0	$ 9,091.9
Fuel and Purchased Electricity	3,488.9	3,142.7	3,079.3
Gross Margin	6,156.6	6,049.3	6,012.6
Other Operation and Maintenance	2,959.8	2,760.7	2,726.6
Asset Impairments and Other Related Charges	3.4	33.6	10.5
Depreciation and Amortization	1,316.2	1,142.5	1,073.8
Taxes Other Than Income Taxes	433.2	413.3	390.8
Operating Income	1,444.0	1,699.2	1,810.9
Interest and Investment Income	11.7	6.8	4.8
Carrying Costs Income	5.3	15.2	10.5
Allowance for Equity Funds Used During Construction	35.4	28.0	45.5
Non-Service Cost Components of Net Periodic Benefit Cost	69.9	23.5	23.7
Interest Expense	(567.8)	(540.0)	(522.1)
Income Before Income Tax Expense and Equity Earnings (Loss)	998.5	1,232.7	1,373.3
Income Tax Expense	5.7	425.6	397.3
Equity Earnings (Loss) of Unconsolidated Subsidiaries	2.7	(3.8)	8.0
Net Income	995.5	803.3	984.0
Net Income Attributable to Noncontrolling Interests	5.0	12.8	4.1
Earnings Attributable to AEP Common Shareholders	$ 990.5	$ 790.5	$ 979.9

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Years Ended December 31,		
	2018	**2017**	**2016**
	(in millions of KWhs)		
Retail:			
Residential	33,903	30,817	32,606
Commercial	24,813	24,423	25,229
Industrial	35,378	34,676	34,029
Miscellaneous	2,326	2,275	2,316
Total Retail	96,420	92,191	94,180
Wholesale (a)	22,682	25,098	23,081
Total KWhs	119,102	117,289	117,261

(a) Includes off-system sales, municipalities and cooperatives, unit power and other wholesale customers.

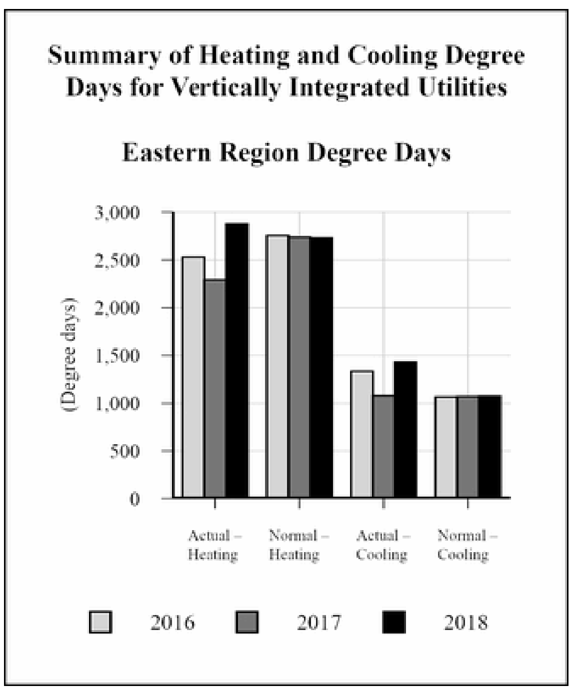


Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues. In general, degree day changes in the eastern region have a larger effect on revenues than changes in the western region due to the relative size of the two regions and the number of customers within each region.

Summary of Heating and Cooling Degree Days for Vertically Integrated Utilities

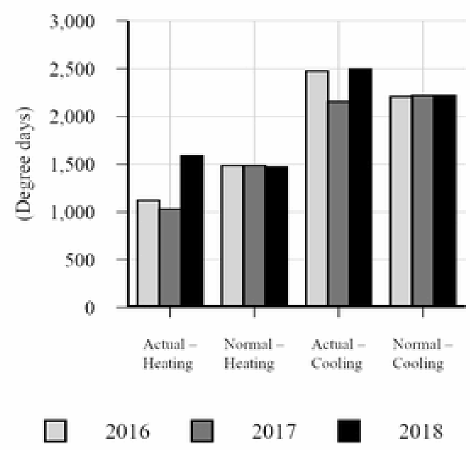
	Years Ended December 31,		
	2018	**2017**	**2016**
		(in degree days)	
Eastern Region			
Actual – Heating (a)	2,886	2,298	2,541
Normal – Heating (b)	2,738	2,746	2,767
Actual – Cooling (c)	1,443	1,088	1,345
Normal – Cooling (b)	1,083	1,078	1,075
Western Region			
Actual – Heating (a)	1,599	1,040	1,130
Normal – Heating (b)	1,475	1,494	1,495
Actual – Cooling (c)	2,502	2,164	2,480
Normal – Cooling (b)	2,230	2,229	2,215

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Cooling degree days are calculated on a 65 degree temperature base.



Summary of Heating and Cooling Degree Days for Vertically Integrated Utilities

Western Region Degree Days



2018 Compared to 2017

Reconciliation of Year Ended December 31, 2017 to Year Ended December 31, 2018
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Year Ended December 31, 2017	$	790.5
Changes in Gross Margin:		
Retail Margins		104.7
Off-system Sales		(12.9)
Transmission Revenues		32.9
Other Revenues		(17.4)
Total Change in Gross Margin		107.3
Changes in Expenses and Other:		
Other Operation and Maintenance		(199.1)
Asset Impairments and Other Related Charges		30.2
Depreciation and Amortization		(173.7)
Taxes Other Than Income Taxes		(19.9)
Interest and Investment Income		4.9
Carrying Costs Income		(9.9)
Allowance for Equity Funds Used During Construction		7.4
Non-Service Cost Components of Net Periodic Pension Cost		46.4
Interest Expense		(27.8)
Total Change in Expenses and Other		(341.5)
Income Tax Expense		419.9
Equity Earnings (Loss) of Unconsolidated Subsidiaries		6.5
Net Income Attributable to Noncontrolling Interests		7.8
Year Ended December 31, 2018	$	990.5

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** increased $105 million primarily due to the following:
  - A $251 million increase in weather-related usage across all regions primarily in the residential and commercial classes.
  - The effect of rate proceedings in AEP’s service territories which included:
    - A $71 million increase from base rate proceedings for I&M, inclusive of a $47 million decrease due to the impact of Tax Reform in the Indiana jurisdiction.
    - A $52 million increase for PSO due to new base rates implemented in March 2018, inclusive of a $27 million decrease due to the change in the corporate federal tax rate.
    - A $44 million increase for SWEPCo due to rider and base rate revenue increases in Texas, Louisiana and Arkansas.
  - A $33 million increase for I&M in FERC generation wholesale municipal and cooperative revenues primarily due to the annual formula rate true-up and changes to the formula rate.
  - A $22 million increase in revenue from rate riders at PSO. This increase was partially offset by corresponding increases to riders/trackers recognized in other expense items below.

  These increases were partially offset by:
  - A $168 million decrease due to riders and customer provisions for refund related to Tax Reform. This decrease was offset in Income Tax Expense below.
  - A $91 million reduction at APCo and WPCo in deferred fuel under-recovery related to the West Virginia Tax Reform settlements. This decrease was offset in Income Tax Expense below.

- A $50 million decrease due to lower weather-normalized wholesale margins, primarily due to SWEPCo and I&M wholesale customer load loss from contracts that expired at the end of 2017.
- A $29 million decrease in weather-normalized retail margins primarily in the commercial class.
- A $25 million increase at APCo in net ENEC recoverable PJM expenses that were offset below.
- A $16 million decrease at PSO related to the System Reliability Rider that ended in August 2017. This decrease was partially offset by a corresponding decrease recognized in other expense items below.
- A $10 million increase at APCo in non-recoverable fuel expense related to Virginia legislation.

- **Margins from Off-system Sales** decreased $13 million primarily due to mid-year changes in the OSS sharing mechanism at I&M.
- **Transmission Revenues** increased $33 million primarily due to the following:
  - A $25 million increase at SWEPCo from continued SPP transmission investments.
  - A $22 million increase due to the annual formula rate true-up and decreased PJM provisions.

  These increases were partially offset by:
  - A $16 million decrease at SWEPCo from a 2018 provision for refund related to revenues recorded in prior periods on certain transmission assets that management believes should not have been included in the SPP formula rate.
- **Other Revenues** decreased $17 million primarily due to reduced rates for KPCo Demand Side Management programs beginning in 2018. This decrease was partially offset in Other Operation and Maintenance expenses below.

Expenses and Other, Income Tax Expense, Equity Earnings (Loss) of Unconsolidated Subsidiaries and Net Income Attributable to Noncontrolling Interests changed between years as follows:

- **Other Operation and Maintenance** expenses increased $199 million primarily due to the following:
  - A $46 million increase in plant outage and maintenance expenses primarily for I&M and KPCo.
  - A $42 million increase in SPP transmission services.
  - A $40 million increase in expenses at APCo and WPCo due to the extinguishment of regulatory asset balances as agreed to within the West Virginia Tax Reform settlement. This increase was partially offset in Retail Margins above and Income Tax Expense below.
  - A $28 million increase in vegetation management primarily for I&M and APCo.
  - A $27 million increase due to the Wind Catcher Project for SWEPCo and PSO.
  - A $27 million increase in storm-related expenses primarily for APCo.
  - A $26 million increase in employee-related expenses.
  - A $9 million increase due to an increase in estimated expense for claims related to asbestos exposure.
  - A $7 million increase in factoring expense.

  These increases were partially offset by:
  - A $70 million decrease in PJM transmission expenses primarily due to the annual formula rate true-up.
- **Asset Impairments and Other Related Charges** decreased $30 million primarily due to the following:
  - A $34 million decrease at SWEPCo due to Welsh Plant, Unit 2 and Turk Plant asset impairments and other charges related to the 2016 Texas Base Rate Case and the 2017 Louisiana Turk Plant Prudence Review.

  This decrease was partially offset by:
  - A $4 million increase at APCo due to the impairment of assets related to capacity management projects and other investments.
- **Depreciation and Amortization** expenses increased $174 million primarily due to a higher depreciable base and increased depreciation rates approved at I&M, PSO and SWEPCo.
- **Taxes Other Than Income Taxes** increased $20 million primarily due to:
  - A $10 million increase in state and local taxes due to higher reported taxable KWh and taxable revenues and a prior period refund.
  - A $9 million increase in property taxes driven by an increase in utility plant.
- **Interest and Investment Income** increased $5 million primarily due to an increase in interest received from the Utility Money Pool as a result of increased investment in 2018 by SWEPCo and I&M.
- **Carrying Costs Income** decreased $10 million primarily due to a decrease in carrying charges for certain riders at I&M.

- **Allowance for Equity Funds Used During Construction** increased $7 million primarily due to an increase in construction activity at APCo and SWEPCo.
- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $46 million primarily due to favorable asset returns for the funded Pension and OPEB plans, favorable OPEB cost savings arrangements and the implementation of ASU 2017-07.
- **Interest Expense** increased $28 million primarily due to the following:
  - A $13 million increase primarily due to higher long-term debt balances at I&M.
  - A $10 million increase at PSO primarily due to the 2017 deferral of the debt component of carrying charges on environmental control costs for projects at Northeastern Plant, Unit 3 and Comanche Plant.
  - A $5 million increase at SWEPCo primarily due to interest expense credits in 2017 on Welsh Plant and Flint Creek Plant environmental project deferrals and other interest expense accruals for refunds and true-ups in 2018.
- **Income Tax Expense** decreased $420 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT, other book/tax differences which are accounted for on a flow-through basis and a decrease in pretax book income.
- **Equity Earnings (Loss) of Unconsolidated Subsidiaries** increased $7 million primarily due to a prior period income tax adjustment recognized in 2017.
- **Net Income Attributable to Noncontrolling Interests** decreased $8 million primarily due to 2017 income tax benefits attributable to SWEPCo's noncontrolling interest in Sabine. This decrease was offset by an increase in Income Tax Expense above.

2017 Compared to 2016

Reconciliation of Year Ended December 31, 2016 to Year Ended December 31, 2017
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)

Year Ended December 31, 2016	$	979.9
Changes in Gross Margin:		
Retail Margins		6.6
Off-system Sales		12.0
Transmission Revenues		17.3
Other Revenues		0.8
Total Change in Gross Margin		36.7
Changes in Expenses and Other:		
Other Operation and Maintenance		(34.1)
Asset Impairments and Other Related Charges		(23.1)
Depreciation and Amortization		(68.7)
Taxes Other Than Income Taxes		(22.5)
Interest and Investment Income		2.0
Carrying Costs Income		4.7
Allowance for Equity Funds Used During Construction		(17.5)
Non-Service Cost Components of Net Periodic Pension Cost		(0.2)
Interest Expense		(17.9)
Total Change in Expenses and Other		(177.3)
Income Tax Expense		(28.3)
Equity Earnings (Loss) of Unconsolidated Subsidiaries		(11.8)
Net Income Attributable to Noncontrolling Interests		(8.7)
Year Ended December 31, 2017	$	790.5

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** increased $7 million primarily due to the following:
  - The effect of rate proceedings in AEP's service territories which include:
    - A $74 million increase for SWEPCo primarily due to rider and base rate revenue increases in Texas and Louisiana.
    - A $63 million increase for I&M from rate proceedings primarily in Indiana.
    - A $22 million increase for PSO from base rate increases implemented in 2017 and revenue increases from rate riders.
    - A $6 million increase for KGPCo due to revenue increases from rate riders/trackers.

    For the rate increases described above, $87 million relate to riders/trackers which have corresponding increases in expense items below.
  - A $24 million increase primarily due to reduced fuel and other variable production costs not recovered through fuel clauses or other trackers.
  - A $9 million increase in weather-normalized margins due to higher residential and industrial sales partially offset by lower commercial sales.

  These increases were partially offset by:
  - A $133 million decrease in weather-related usage in the eastern and western regions.
  - A $50 million decrease for I&M and SWEPCo in FERC generation wholesale municipal and cooperative revenues primarily due to an annual formula rate true-up and changes to the annual formula rate.
  - A $9 million decrease for APCo primarily due to prior year recognition of deferred billing in West Virginia as approved by the WVPSC.

- **Margins from Off-system Sales** increased $12 million primarily due to higher market prices and increased sales volume.
- **Transmission Revenues** increased $17 million primarily due the following:
  - A $43 million increase primarily due to increases in formula rates driven by continued investment in transmission assets. This increase was partially offset in Expenses and Other items below.

  This increase was partially offset by:
  - A $26 million decrease primarily due to I&M's annual formula rate true-up and reduced net PJM Network Integration Transmission Service revenues resulting from increased affiliated transmission-related charges.

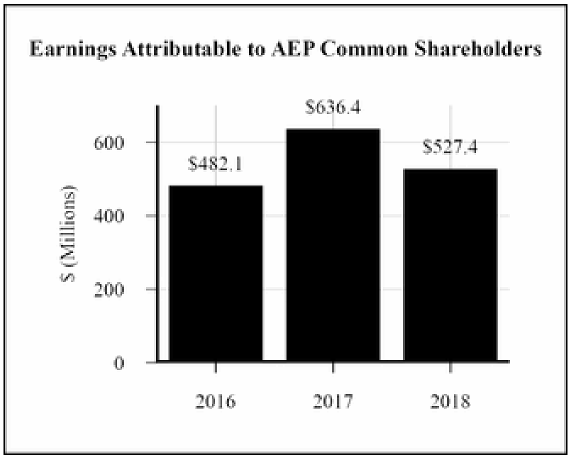
Expenses and Other, Income Tax Expense, Equity Earnings (Loss) of Unconsolidated Subsidiaries and Net Income Attributable to Noncontrolling Interests changed between years as follows:

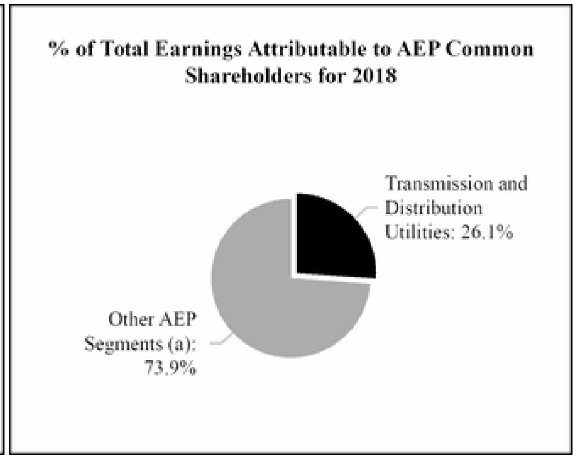
- **Other Operation and Maintenance** expenses increased $34 million primarily due to the following:
  - A $134 million increase in recoverable expenses, primarily PJM expenses, fuel support and energy efficiency expenses fully recovered in rate recovery riders/trackers within Gross Margin above.
  - A $14 million increase due to the Wind Catcher Project for PSO and SWEPCo.

  These increases were partially offset by:
  - A $49 million decrease in employee-related expenses.
  - A $36 million decrease in charitable contributions, primarily to the AEP Foundation.
  - A $17 million decrease in planned plant outages and maintenance primarily in the western region.
  - A $5 million decrease due to an increase in gain on sales of property in 2017.
  - A $4 million decrease due to the reduction of an environmental liability at I&M.
- **Asset Impairments and Other Related Charges** increased $23 million primarily due to the following:
  - A $34 million increase at SWEPCo due to asset impairments of Turk Plant and Welsh Plant, Unit 2 and other charges related to the Texas base rate case.

  This increase was partially offset by:
  - An $11 million decrease due to the impairment of I&M's Price River Coal reserves in 2016.
- **Depreciation and Amortization** expenses increased $69 million primarily due to the following:
  - A $61 million increase primarily due to higher depreciable base.
  - A $22 million increase due to amortization of capitalized software costs.
- **Taxes Other Than Income Taxes** increased $23 million primarily due to higher property taxes.
- **Carrying Costs Income** increased $5 million primarily due to increased deferred carrying charges at I&M for a Cook Life Cycle Management project.
- **Allowance for Equity Funds Used During Construction** decreased $18 million primarily due to completed environmental projects for I&M, PSO and SWEPCo.
- **Interest Expense** increased $18 million primarily due to the following:
  - A $10 million increase primarily due to higher long-term debt balances at I&M.
  - An $8 million increase due to lower AFUDC borrowed funds resulting from reduced CWIP balances.
- **Income Tax Expense** increased $28 million primarily due to the recording of favorable state and federal income tax adjustments in 2016, the recording of federal income tax adjustments related to Tax Reform and other book/tax differences which are accounted for on a flow-through basis, partially offset by a decrease in pretax book income.
- **Equity Earnings (Loss) of Unconsolidated Subsidiaries** decreased $12 million primarily due to a prior period income tax adjustment for DHLC, a SWEPCo unconsolidated subsidiary.
- **Net Income Attributable to Noncontrolling Interests** increased $9 million primarily due to income tax benefits attributable to SWEPCo's noncontrolling interest in Sabine. This increase was offset by a decrease in Income Tax Expense.

TRANSMISSION AND DISTRIBUTION UTILITIES





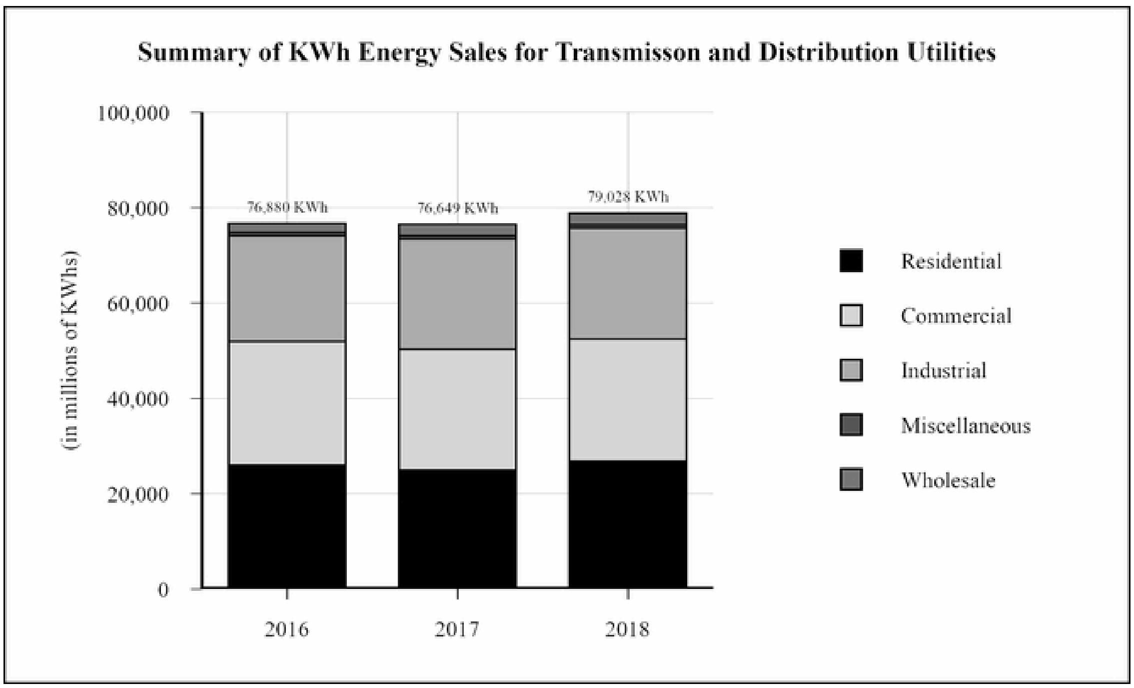
(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment.

Transmission and Distribution Utilities	Years Ended December 31, 2018	2017	2016
	(in millions)		
Revenues	$ 4,653.1	$ 4,419.3	$ 4,422.4
Purchased Electricity	858.3	835.3	837.1
Generation Deferrals	—	—	(82.7)
Amortization of Generation Deferrals	223.9	229.2	242.9
Gross Margin	3,570.9	3,354.8	3,425.1
Other Operation and Maintenance	1,541.7	1,199.3	1,395.4
Depreciation and Amortization	734.1	667.5	649.9
Taxes Other Than Income Taxes	545.3	513.7	494.3
Operating Income	749.8	974.3	885.5
Interest and Investment Income	4.2	7.7	14.8
Carrying Costs Income	1.7	3.6	20.0
Allowance for Equity Funds Used During Construction	29.9	13.2	15.1
Non-Service Cost Components of Net Periodic Benefit Cost	32.3	8.9	8.7
Interest Expense	(248.1)	(244.1)	(256.9)
Income Before Income Tax Expense	569.8	763.6	687.2
Income Tax Expense	42.4	127.2	205.1
Net Income	527.4	636.4	482.1
Net Income Attributable to Noncontrolling Interests	—	—	—
Earnings Attributable to AEP Common Shareholders	$ 527.4	$ 636.4	$ 482.1

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Years Ended December 31,		
	2018	**2017**	**2016**
	(in millions of KWhs)		
Retail:			
Residential	27,041	25,108	26,191
Commercial	25,555	25,390	25,922
Industrial	23,310	23,082	22,179
Miscellaneous	681	682	700
Total Retail (a)	76,587	74,262	74,992
Wholesale (b)	2,441	2,387	1,888
Total KWhs	79,028	76,649	76,880

(a) Represents energy delivered to distribution customers.
(b) Primarily Ohio's contractually obligated purchases of OVEC power sold into PJM.

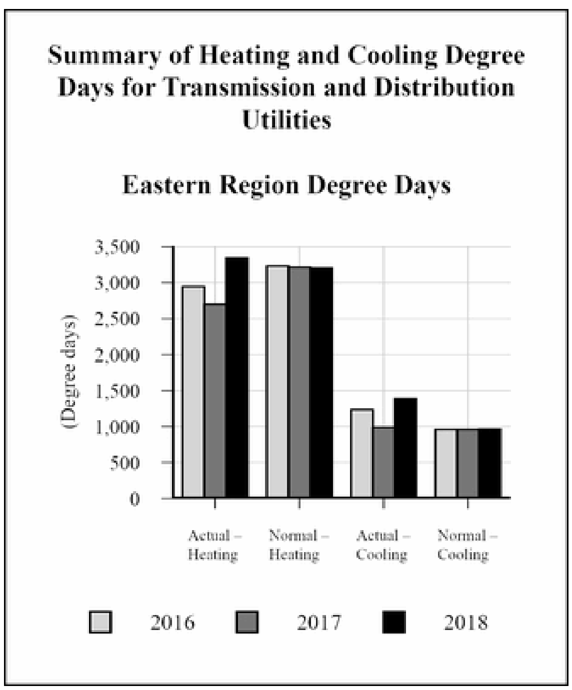


Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues. In general, degree day changes in the eastern region have a larger effect on revenues than changes in the western region due to the relative size of the two regions and the number of customers within each region.

Summary of Heating and Cooling Degree Days for Transmission and Distribution Utilities

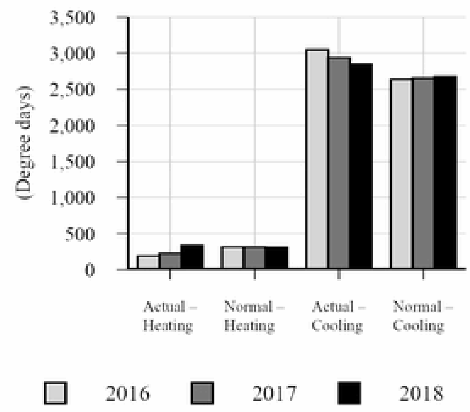
	Years Ended December 31,		
	2018	**2017**	**2016**
		(in degree days)	
Eastern Region			
Actual – Heating (a)	3,357	2,709	2,957
Normal – Heating (b)	3,215	3,225	3,245
Actual – Cooling (c)	1,402	1,002	1,248
Normal – Cooling (b)	980	974	969
Western Region			
Actual – Heating (a)	354	239	201
Normal – Heating (b)	325	330	328
Actual – Cooling (d)	2,861	2,950	3,058
Normal – Cooling (b)	2,688	2,669	2,648

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Eastern Region cooling degree days are calculated on a 65 degree temperature base.
(d) Western Region cooling degree days are calculated on a 70 degree temperature base.



Summary of Heating and Cooling Degree Days for Transmission and Distribution Utilities

Western Region Degree Days



2018 Compared to 2017

Reconciliation of Year Ended December 31, 2017 to Year Ended December 31, 2018
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Year Ended December 31, 2017	$	636.4
Changes in Gross Margin:		
Retail Margins		152.2
Off-system Sales		63.3
Transmission Revenues		(1.6)
Other Revenues		2.2
Total Change in Gross Margin		216.1
Changes in Expenses and Other:		
Other Operation and Maintenance		(342.4)
Depreciation and Amortization		(66.6)
Taxes Other Than Income Taxes		(31.6)
Interest and Investment Income		(3.5)
Carrying Costs Income		(1.9)
Allowance for Equity Funds Used During Construction		16.7
Non-Service Cost Component of Net Periodic Benefit Cost		23.4
Interest Expense		(4.0)
Total Change in Expenses and Other		(409.9)
Income Tax Expense		84.8
Year Ended December 31, 2018	$	527.4

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of purchased electricity and amortization of generation deferrals were as follows:

- **Retail Margins** increased $152 million primarily due to the following:
  - A $173 million net increase in Ohio Basic Transmission Cost Rider revenues and recoverable PJM expenses. This increase was partially offset by an increase in Other Operation and Maintenance below.
  - A $77 million increase in Ohio revenues associated with the Universal Service Fund (USF). This increase was offset by a corresponding increase in Other Operation and Maintenance expenses below.
  - A $16 million increase in Ohio rider revenues associated with the DIR. This increase was partially offset in various expenses below.
  - A $12 million increase in Texas revenues associated with the Distribution Cost Recovery Factor revenue rider.
  - A $10 million increase in Texas revenues associated with the Transmission Cost Recovery Factor revenue rider. This increase was offset by an increase in Other Operation and Maintenance expenses below.
  - A $10 million increase in rider revenues recovering state excise taxes due to an increase in metered KWh in Ohio. This increase was offset by a corresponding increase in Taxes Other Than Income Taxes below.

  These increases were partially offset by:
  - A $46 million decrease due to adjustments to the distribution decoupling under-recovery balance as a result of the 2018 Ohio Tax Reform settlement. This decrease was offset in Income Tax Expense below.
  - A $42 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
  - A $41 million decrease in Ohio due to prior year over-recoveries and the recovery of lower current year losses from a power contract with OVEC. This decrease was offset by a corresponding increase in Margins from Off-system Sales below.

- **Margins from Off-system Sales** increased $63 million primarily due to the following:
  - A $41 million increase due to prior year over-recoveries and lower current year losses from a power contract with OVEC in Ohio which was offset in Retail Margins above as a result of the OVEC PPA rider beginning in January 2017.
  - A $22 million increase due to higher affiliated PPA revenues in Texas, which were partially offset by a corresponding increase in Other Operation and Maintenance expenses below.
- **Transmission Revenues** decreased $2 million primarily due to the following:
  - An $11 million decrease due to the 2018 provisions for customer refunds in Texas due to Tax Reform. This decrease was offset in Income Tax Expense below.
  - An $11 million decrease due to lower rates in Texas in order to pass the benefits of Tax Reform on to customers. This decrease was offset in Income Tax Expense below.
  - A $10 million decrease in Ohio primarily due to the 2018 provisions for customer refunds due to Tax Reform, partially offset by increased revenues due to additional transmission investments. This decrease was offset in Income Tax Expense below.

  These decreases were offset by:
  - A $30 million increase due to recovery of increased transmission investment in ERCOT.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses increased $342 million primarily due to the following:
  - A $226 million increase primarily in transmission expenses that were fully recovered in rate riders/trackers within Gross Margins above.
  - A $77 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset by a corresponding increase in Retail Margins above.
  - A $19 million increase in affiliated PPA expenses in Texas. This increase was offset by an increase in Margins from Off-system sales above.

  These increases were partially offset by:
  - A $58 million decrease in Ohio PJM expenses primarily related to the annual formula rate true-up that will be refunded in future periods.
- **Depreciation and Amortization** expenses increased $67 million primarily due to the following:
  - A $40 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
  - A $9 million increase in securitization amortizations related to Transition Funding in Texas. This increase was offset in Other Revenues and Interest Expense.
  - An $8 million increase in amortization due to capitalized software.
- **Taxes Other Than Income Taxes** increased $32 million primarily due to the following:
  - An $18 million increase in property taxes due to additional investments in transmission and distribution assets and higher tax rates.
  - A $12 million increase in rider revenues recovering state excise taxes due to an increase in metered KWhs. This increase was offset in Retail Margins above.
- **Allowance for Equity Funds Used During Construction** increased $17 million primarily due to increased transmission projects in Texas.
- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $23 million primarily due to favorable asset returns for the funded Pension and OPEB plans, favorable OPEB cost savings arrangements and the implementation of ASU 2017-07.
- **Income Tax Expense** decreased $85 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income, partially offset by the benefit related to the remeasurement of deferred tax liabilities recognized in 2017 as a result of Tax Reform.

2017 Compared to 2016

Reconciliation of Year Ended December 31, 2016 to Year Ended December 31, 2017
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)

Year Ended December 31, 2016	$	482.1
Changes in Gross Margin:		
Retail Margins		(25.7)
Off-system Sales		(83.8)
Transmission Revenues		32.3
Other Revenues		6.9
Total Change in Gross Margin		(70.3)
Changes in Expenses and Other:		
Other Operation and Maintenance		196.1
Depreciation and Amortization		(17.6)
Taxes Other Than Income Taxes		(19.4)
Interest and Investment Income		(7.1)
Carrying Costs Income		(16.4)
Allowance for Equity Funds Used During Construction		(1.9)
Non-Service Cost Component of Net Periodic Benefit Cost		0.2
Interest Expense		12.8
Total Change in Expenses and Other		146.7
Income Tax Expense		77.9
Year Ended December 31, 2017	$	636.4

The major components of the decrease in Gross Margin, defined as revenues less the related direct cost of purchased electricity and amortization of generation deferrals were as follows:

- **Retail Margins** decreased $26 million primarily due to the following:
  - A $178 million decrease in Ohio revenues associated with the Universal Service Fund (USF) surcharge rate decrease. This decrease was offset by a corresponding decrease in Other Operating and Maintenance expenses below.
  - An $83 million decrease due to the impact of a 2016 regulatory deferral of capacity costs related to OPCo's December 2016 Global Settlement.
  - A $23 million net decrease in recovery of equity carrying charges related to the PIRR in Ohio, net of associated amortizations.
  - A $21 million decrease in revenues associated with smart grid riders in Ohio. This decrease was offset in various expense items below.
  - A $15 million decrease in weather-normalized margins, primarily in the residential class.
  - A $9 million decrease in Energy Efficiency/Peak Demand Reduction rider revenues and associated deferrals in Ohio. This decrease was offset by a corresponding decrease in Other Operation and Maintenance expenses below.
  - A $7 million decrease in state excise taxes due to a decrease in metered KWh in Ohio. This decrease was offset by a corresponding decrease in Taxes Other Than Income Taxes.

  These decreases were partially offset by:
  - A $150 million net increase due to the impact of 2016 provisions for refund primarily related to OPCo’s December 2016 Global Settlement.

- A $62 million increase in Ohio due to the recovery of losses from a power contract with OVEC. The PUCO approved a PPA rider beginning in January 2017 to recover any net margin related to the deferral of OVEC losses starting in June 2016. This increase was offset by a corresponding decrease in Margins from Off-System Sales below.
- A $45 million increase in Texas revenues associated with the Distribution Cost Recovery Factor revenue rider.
- A $31 million net increase in Ohio Basic Transmission Cost Rider revenues and recoverable PJM expenses. This increase was offset by a corresponding increase in Other Operation and Maintenance below.
- A $16 million net increase in Ohio RSR revenues less associated amortizations.
- A $7 million increase in Ohio rider revenues associated with the DIR. This increase was partially offset in other expense items below.

- **Margins from Off-system Sales** decreased $84 million primarily due to the following:
  - A $62 million decrease in Ohio due to current year losses from a power contract with OVEC, which was offset in Retail Margins above as a result of the OVEC PPA rider beginning in January 2017.
  - A $41 million decrease in Ohio due to the 2016 reversal of prior year provisions for regulatory loss.

  This decrease was partially offset by:
  - An $18 million increase in Ohio primarily due to the impact of prior year losses from a power contract with OVEC which was not included in the OVEC PPA rider.
- **Transmission Revenues** increased $32 million primarily due to recovery of increased transmission investment in ERCOT.
- **Other Revenues** increased $7 million primarily due the following:
  - A $12 million increase in securitization revenue in Texas. This increase was offset below in Depreciation and Amortization and in Interest Expense.

  This increase was partially offset by:
  - A $4 million decrease in Texas performance bonus revenues and true-ups related to energy efficiency programs.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $196 million primarily due to the following:
  - A $178 million decrease in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This decrease was offset by a corresponding decrease in Retail Margins above.
  - A $29 million decrease primarily due to charitable donations in 2016, including the AEP Foundation.
  - A $17 million decrease in employee-related expenses.

  These decreases were partially offset by:
  - A $19 million increase in recoverable expenses primarily in PJM as well as increased ERCOT transmission expenses, partially offset by energy efficiency expenses that were fully recovered in rate recovery riders/trackers within Gross Margins above.
  - A $14 million increase in PJM expenses related to the annual formula rate true-up that will be recovered in 2018.
  - A $6 million increase in non-deferred storm expenses, primarily in the Texas region.
- **Depreciation and Amortization** expenses increased $18 million primarily due to the following:
  - A $21 million increase due to securitization amortizations related to Texas securitized transition funding. This increase was offset in Other Revenues above and in Interest Expense below.
  - A $15 million increase in depreciation expense primarily due to an increase in depreciable base of transmission and distribution assets.
  - An $8 million increase due to amortization of capitalized software costs.

  These increases were partially offset by:
  - An $8 million decrease due to recoveries of transmission cost rider carrying costs in Ohio. This decrease was partially offset in Retail Margins above.
  - An $8 million decrease in recoverable DIR depreciation expense in Ohio.
  - A $7 million decrease in recoverable smart grid rider depreciation expenses in Ohio. This decrease was partially offset in Retail Margins above.

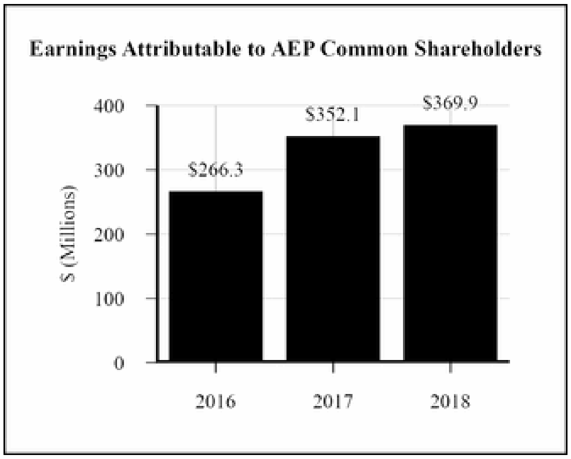
- **Taxes Other Than Income Taxes** increased $19 million primarily due to the following:
  - A $26 million increase in property taxes due to additional investments in transmission and distribution assets and higher tax rates.

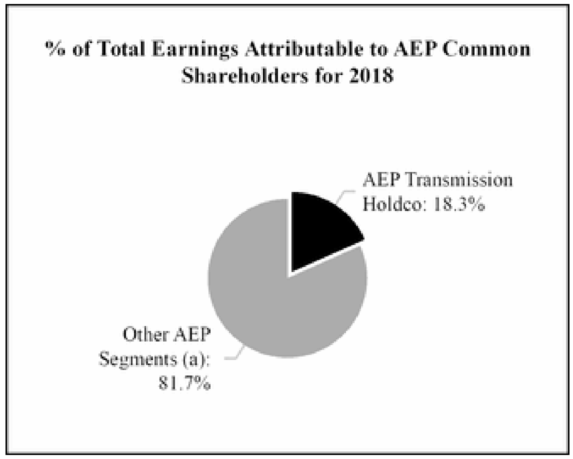
  This increase was partially offset by:
  - A $7 million decrease in state excise taxes due to a decrease in metered KWhs in Ohio. This decrease was offset in Retail Margins above.
- **Interest and Investment Income** decreased $7 million primarily due to a prior year tax adjustment in Texas.
- **Carrying Costs Income** decreased $16 million primarily due to the impact of a 2016 regulatory deferral of capacity related carrying costs in Ohio.
- **Interest Expense** decreased $13 million primarily due to the following:
  - A $10 million decrease primarily due to the maturity of a senior unsecured note in June 2016 in Ohio.
  - A $9 million decrease in the Texas securitization transition assets due to the final maturity of the first Texas securitization bond. This decrease was offset above in Other Revenues and in Depreciation and Amortization.

  These decreases were partially offset by:
  - A $7 million increase due to the issuance of long-term debt in September 2017 in Texas.
- **Income Tax Expense** decreased $78 million primarily due to the following:
  - A $138 million decrease due to the recording of federal income tax adjustments related to Tax Reform.

  This decrease was partially offset by:
  - A $60 million increase in pretax book income and by the recording of federal and state income tax adjustments.

AEP TRANSMISSION HOLDCO



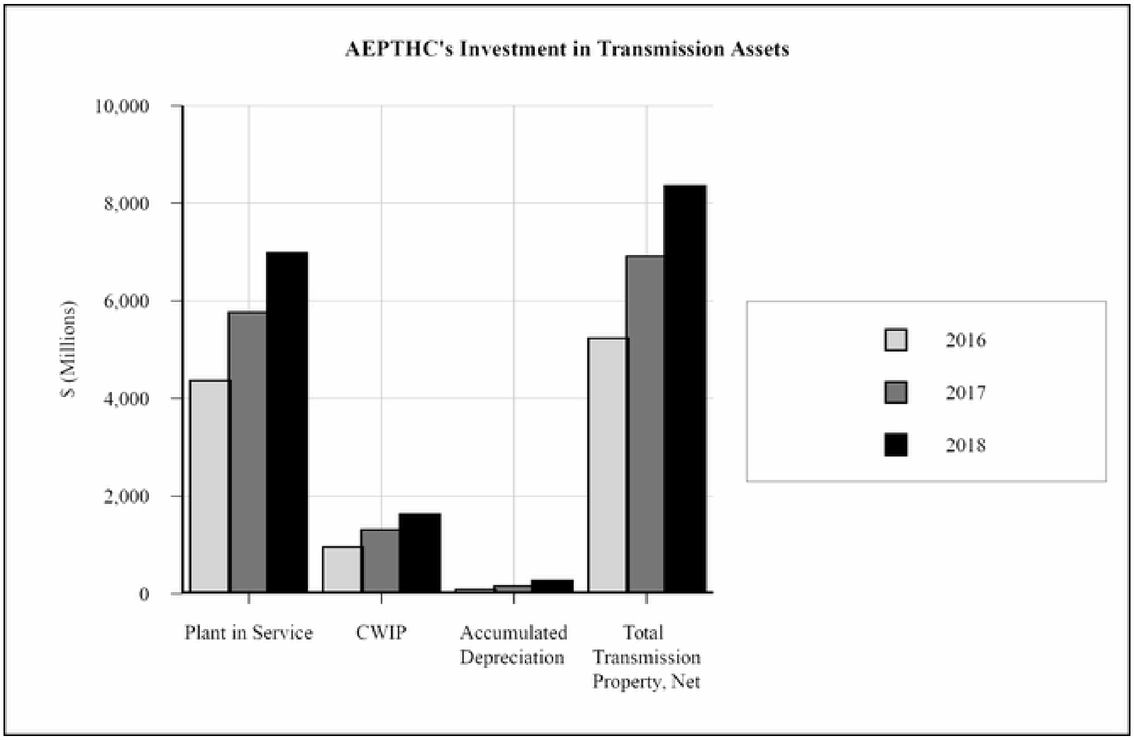


(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment.

AEP Transmission Holdco	Years Ended December 31, 2018	2017	2016
	(in millions)		
Transmission Revenues	$ 804.1	$ 766.7	$ 512.8
Other Operation and Maintenance	105.6	74.7	55.5
Depreciation and Amortization	137.8	102.2	67.1
Taxes Other Than Income Taxes	142.3	114.0	88.7
Operating Income	418.4	475.8	301.5
Interest and Investment Income	2.5	1.2	0.4
Carrying Costs Expense	(0.4)	(0.2)	(0.3)
Allowance for Equity Funds Used During Construction	67.2	52.5	52.2
Non-Service Cost Components of Net Periodic Benefit Cost	2.6	0.3	0.2
Interest Expense	(90.7)	(72.8)	(50.3)
Income Before Income Tax Expense and Equity Earnings	399.6	456.8	303.7
Income Tax Expense	95.3	189.8	134.1
Equity Earnings of Unconsolidated Subsidiaries	68.7	88.6	99.7
Net Income	373.0	355.6	269.3
Net Income Attributable to Noncontrolling Interests	3.1	3.5	3.0
Earnings Attributable to AEP Common Shareholders	$ 369.9	$ 352.1	$ 266.3

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	December 31, 2018	2017	2016
	(in millions)		
Plant in Service	$ 7,008.4	$ 5,784.6	$ 4,386.0
Construction Work in Progress	1,651.1	1,325.6	968.0
Accumulated Depreciation and Amortization	282.8	176.6	101.4
Total Transmission Property, Net	$ 8,376.7	$ 6,933.6	$ 5,252.6



2018 Compared to 2017

Reconciliation of Year Ended December 31, 2017 to Year Ended December 31, 2018
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Year Ended December 31, 2017	$	352.1
Changes in Transmission Revenues:		
Transmission Revenues		37.4
Total Change in Transmission Revenues		37.4
Changes in Expenses and Other:		
Other Operation and Maintenance		(30.9)
Depreciation and Amortization		(35.6)
Taxes Other Than Income Taxes		(28.3)
Interest and Investment Income		1.3
Carrying Costs Expense		(0.2)
Allowance for Equity Funds Used During Construction		14.7
Non-Service Cost Components of Net Periodic Pension Cost		2.3
Interest Expense		(17.9)
Total Change in Expenses and Other		(94.6)
Income Tax Expense		94.5
Equity Earnings of Unconsolidated Subsidiaries		(19.9)
Net Income Attributable to Noncontrolling Interests		0.4
Year Ended December 31, 2018	$	369.9

The major components of the increase in transmission revenues, which consists of wholesale sales to affiliates and nonaffiliates were as follows:

- **Transmission Revenues** increased $37 million primarily due to:
  - A $101 million increase in revenues driven by an increase in the formula rate revenue requirement primarily driven by continued investment in transmission assets. This increase includes the impact of the reduction in revenue related to Tax Reform, which was offset by a decrease in Income Tax Expense below.

  This increase was partially offset by:
  - A $64 million decrease in revenues due to a lower annual formula rate true-up in 2018 driven by implementing forward looking formula rates in 2017.

Expenses and Other, Income Tax Expense and Equity Earnings of Unconsolidated Subsidiaries changed between years as follows:

- **Other Operation and Maintenance** expenses increased $31 million primarily due to increased transmission investment.
- **Depreciation and Amortization** expenses increased $36 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $28 million primarily due to higher property taxes as a result of increased transmission investment.
- **Allowance for Equity Funds Used During Construction** increased $15 million primarily due to increased transmission investment resulting in a higher CWIP balance.
- **Interest Expense** increased $18 million primarily due to the following:
  - A $23 million increase primarily due to higher long-term debt balances.

  This increase was partially offset by:
  - A $5 million decrease due to higher AFUDC borrowed funds resulting from a higher CWIP balance.

- **Income Tax Expense** decreased $95 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.
- **Equity Earnings of Unconsolidated Subsidiaries** decreased $20 million primarily due to lower pretax equity earnings at ETT due to decreased revenues driven by Tax Reform and an ETT rate reduction implemented in March 2017.

2017 Compared to 2016

Reconciliation of Year Ended December 31, 2016 to Year Ended December 31, 2017
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)

Year Ended December 31, 2016	$	266.3
Changes in Transmission Revenues:		
Transmission Revenues		253.9
Total Change in Transmission Revenues		253.9
Changes in Expenses and Other:		
Other Operation and Maintenance		(19.2)
Depreciation and Amortization		(35.1)
Taxes Other Than Income Taxes		(25.3)
Interest and Investment Income		0.8
Carrying Costs Expense		0.1
Allowance for Equity Funds Used During Construction		0.3
Non-Service Cost Components of Net Periodic Pension Cost		0.1
Interest Expense		(22.5)
Total Change in Expenses and Other		(100.8)
Income Tax Expense		(55.7)
Equity Earnings of Unconsolidated Subsidiaries		(11.1)
Net Income Attributable to Noncontrolling Interests		(0.5)
Year Ended December 31, 2017	$	352.1

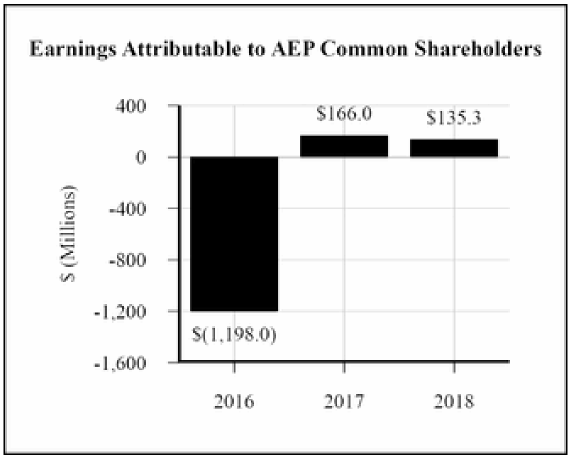
The major components of the increase in transmission revenues, which consists of wholesale sales to affiliates and non-affiliates were as follows:

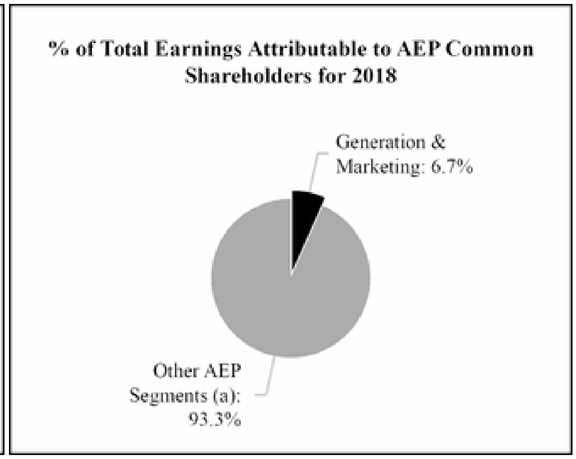
- **Transmission Revenues** increased $254 million primarily due to:
  - A $246 million increase in formula rates driven by the favorable impact of the modification of the PJM OATT formula combined with an increase driven by continued investments in transmission assets.
  - A $7 million increase due to rental revenue related to various AEPTCo facilities.

Expenses and Other, Income Tax Expense and Equity Earnings of Unconsolidated Subsidiaries changed between years as follows:

- **Other Operation and Maintenance** expenses increased $19 million primarily due to increased transmission investment.
- **Depreciation and Amortization** expenses increased $35 million primarily due to higher depreciable base.
- **Taxes Other Than Income Taxes** increased $25 million primarily due to increased property taxes as a result of additional transmission investment.
- **Interest Expense** increased $23 million primarily due to higher outstanding long-term debt balances.
- **Income Tax Expense** increased $56 million primarily due to an increase in pretax book income.
- **Equity Earnings of Unconsolidated Subsidiaries** decreased $11 million primarily due to lower earnings at ETT resulting from increased property taxes, depreciation expense, and decreased AFUDC, partially offset by increased revenues. The revenue increase is primarily due to interim rate increases in the third quarter of 2016 and higher loads, partially offset by an ETT rate reduction that went into effect in March 2017.

GENERATION & MARKETING



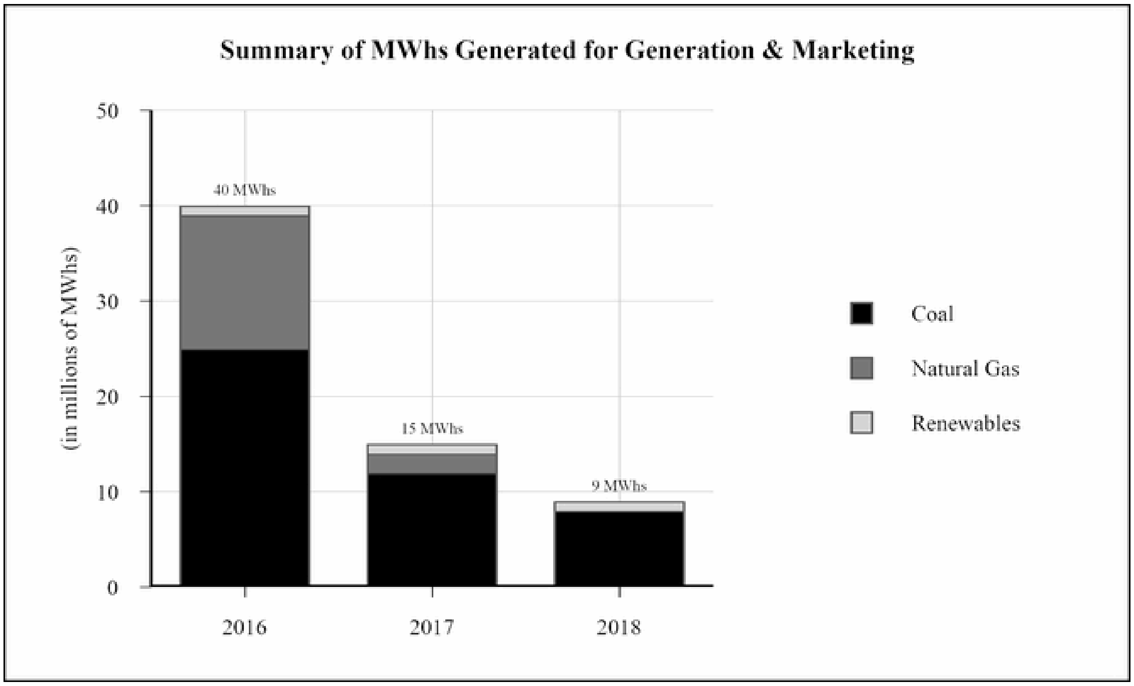


(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment.

Generation & Marketing	Years Ended December 31, 2018	2017	2016
		(in millions)	
Revenues	$ 1,940.3	$ 1,875.1	$ 2,986.0
Fuel, Purchased Electricity and Other	1,537.3	1,377.2	1,948.6
Gross Margin	403.0	497.9	1,037.4
Other Operation and Maintenance	229.3	279.5	426.5
Asset Impairments and Other Related Charges	47.7	53.5	2,257.3
Gain on Sale of Merchant Generation Assets	—	(226.4)	—
Depreciation and Amortization	41.0	24.2	154.6
Taxes Other Than Income Taxes	13.4	12.1	37.6
Operating Income (Loss)	71.6	355.0	(1,838.6)
Interest and Investment Income	13.1	10.3	1.4
Allowance for Equity Funds Used During Construction	—	—	0.4
Non-Service Cost Components of Net Periodic Benefit Cost	15.2	8.9	8.1
Interest Expense	(14.9)	(18.5)	(35.8)
Income (Loss) Before Income Tax Expense (Benefit) and Equity Earnings	85.0	355.7	(1,864.5)
Income Tax Expense (Benefit)	(49.2)	189.7	(666.5)
Equity Earnings of Unconsolidated Subsidiaries	0.5	—	—
Net Income (Loss)	134.7	166.0	(1,198.0)
Net Loss Attributable to Noncontrolling Interests	(0.6)	—	—
Earnings (Loss) Attributable to AEP Common Shareholders	$ 135.3	$ 166.0	$ (1,198.0)

Summary of MWhs Generated for Generation & Marketing

	Years Ended December 31,		
	2018	**2017**	**2016**
	(in millions of MWhs)		
Fuel Type:			
Coal	8	12	25
Natural Gas	—	2	14
Renewables	1	1	1
Total MWhs	9	15	40



2018 Compared to 2017

Reconciliation of Year Ended December 31, 2017 to Year Ended December 31, 2018
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Year Ended December 31, 2017	$	166.0
Changes in Gross Margin:		
Generation		(85.8)
Retail, Trading and Marketing		(20.9)
Other		11.8
Total Change in Gross Margin		(94.9)
Changes in Expenses and Other:		
Other Operation and Maintenance		50.2
Asset Impairments and Other Related Charges		5.8
Gain on Sale of Merchant Generation Assets		(226.4)
Depreciation and Amortization		(16.8)
Taxes Other Than Income Taxes		(1.3)
Interest and Investment Income		2.8
Non-Service Cost Components of Net Periodic Benefit Cost		6.3
Interest Expense		3.6
Total Change in Expenses and Other		(175.8)
Income Tax Expense (Benefit)		238.9
Equity Earnings of Unconsolidated Subsidiaries		0.5
Net Loss Attributable to Noncontrolling Interests		0.6
Year Ended December 31, 2018	$	135.3

The major components of the decrease in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, purchased electricity and certain cost of service for retail operations were as follows:

- **Generation** decreased $86 million primarily due to reduced energy margins in 2018 and the reduction of revenues associated with the sale of certain merchant generation assets in 2017.
- **Retail, Trading and Marketing** decreased $21 million primarily due to lower retail margins due to higher market costs and increased competition combined with decreased marketing volumes in 2018.
- **Other Revenue** increased $12 million primarily due to renewable projects placed in-service.

Expenses and Other and Income Tax Expense (Benefit) changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $50 million primarily due to the following:
  - A $38 million decrease in the Stuart Plant asset retirement obligation.
  - A $24 million decrease in expenses due to the closure of the Stuart Plant in 2018.
  - A $9 million decrease in expenses due to the sale of merchant generation assets in 2017.

  These decreases were partially offset by:
  - A $17 million increase due to severance accruals related to announced merchant generation plant retirements.
- **Asset Impairments and Other Related Charges** decreased $6 million primarily due to an $8 million decrease in impairment charges related to Racine partially offset by a $2 million increase in impairment charges related to merchant coal-fired generation assets in 2017.
- **Gain on Sale of Merchant Generation Assets** decreased $226 million due to the sale of certain merchant generation assets in 2017.

- **Depreciation and Amortization** expenses increased $17 million primarily due to a higher depreciable base from increased investments in renewable energy sources.
- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $6 million primarily due to favorable asset returns for funded Pension and OPEB plans, favorable OPEB cost savings arrangement and the implementation of ASU 2017-07.
- **Income Tax Expense (Benefit)** decreased $239 million primarily due to a decrease in pretax book income driven by the gain on sale of certain merchant generation assets in 2017, the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform and the utilization of a $47 million tax capital loss benefit.

2017 Compared to 2016

Reconciliation of Year Ended December 31, 2016 to Year Ended December 31, 2017
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)

Year Ended December 31, 2016	$	(1,198.0)
Changes in Gross Margin:		
Generation		(504.8)
Retail, Trading and Marketing		(48.5)
Other		13.8
Total Change in Gross Margin		(539.5)
Changes in Expenses and Other:		
Other Operation and Maintenance		147.0
Asset Impairments and Other Related Charges		2,203.8
Gain on Sale of Merchant Generation Assets		226.4
Depreciation and Amortization		130.4
Taxes Other Than Income Taxes		25.5
Interest and Investment Income		8.9
Allowance for Equity Funds Used During Construction		(0.4)
Non-Service Cost Components of Net Periodic Benefit Cost		0.8
Interest Expense		17.3
Total Change in Expenses and Other		2,759.7
Income Tax Expense (Benefit)		(856.2)
Year Ended December 31, 2017	$	166.0

The major components of the decrease in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, purchased electricity and certain cost of service for retail operations were as follows:

- **Generation** decreased $505 million primarily due to the reduction of revenues associated with the sale of certain merchant generation assets.
- **Retail, Trading and Marketing** decreased $49 million primarily due to lower retail margins in 2017 combined with the impact of favorable wholesale trading and marketing performance in 2016.
- **Other Revenue** increased $14 million primarily due to renewable projects placed in-service.

Expenses and Other and Income Tax Expense (Benefit) changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $147 million primarily due to decreased plant expenses as a result of the sale of certain merchant generation assets.
- **Asset Impairments and Other Related Charges** decreased $2.2 billion due to the impairment of certain merchant generation assets in 2016, partially offset by a $43 million impairment of Racine in 2017.
- **Gain on Sale of Merchant Generation Assets** increased $226 million due to the sale of certain merchant generation assets.
- **Depreciation and Amortization** expenses decreased $130 million primarily due to the sale and impairment of certain merchant generation assets.

- **Taxes Other Than Income Taxes** decreased $26 million primarily due to the sale of certain merchant generation assets.
- **Interest and Investment Income** increased $9 million primarily due to additional cash invested as a result of the sale of certain merchant generation assets.

- **Interest Expense** decreased $17 million primarily due to reduced debt as a result of the sale of certain merchant generation assets.
- **Income Tax Expense (Benefit)** increased $856 million primarily due to an increase in pretax book income as a result of the impairment of certain merchant generation assets recorded in 2016, a gain on the sale of certain merchant generation assets recorded in 2017 and the recording of federal income tax adjustments related to Tax Reform.

CORPORATE AND OTHER

2018 Compared to 2017

Earnings attributable to AEP Common Shareholders from Corporate and Other decreased from a loss of $32 million in 2017 to a loss of $99 million in 2018 primarily due to:

- A $59 million increase in interest expense as a result of increased debt outstanding.
- A $26 million decrease in business development and other revenues.
- A $20 million impairment of an equity investment and related assets in 2018.
- A $12 million gain recognized on the sale of an equity investment in the third quarter of 2017.

These items were partially offset by:

- A $21 million decrease in general corporate expenses.
- A $16 million decrease in income tax expense primarily related to an $18 million favorable impact resulting from the enactment of Kentucky state tax legislation in the second quarter of 2018, the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform and a decrease in pretax book income. These decreases were partially offset by a $47 million tax capital loss benefit allocated to the Generation & Marketing segment.

2017 Compared to 2016

Earnings attributable to AEP Common Shareholders from Corporate and Other decreased from $81 million in 2016 to a loss of $32 million in 2017 primarily due to the prior year reversal of capital loss valuation allowances related to effectively settling a 2011 audit issue with the IRS and the impact of the pending sale of certain merchant generation assets as well as 2015 tax return adjustments related to the disposition of AEP's commercial barging operations. Earnings attributable to AEP Common Shareholders also decreased due to increased income tax expense in 2017 as a result of federal income tax adjustments related to Tax Reform. These decreases were offset by an increase in pretax book income primarily due to lower operating expenses.

AEP SYSTEM INCOME TAXES

2018 Compared to 2017

Income Tax Expense decreased $854 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.

2017 Compared to 2016

Income Tax Expense increased $1 billion primarily due to an increase in pretax book income in 2017 driven by the impairment of certain merchant generation assets in 2016. The increase in Income Tax Expense is also due to the prior year reversal of a $66 million capital loss valuation allowance related to the pending sale of certain merchant generation assets, the prior year reversal of a $56 million unrealized capital loss valuation allowance where AEP effectively settled a 2011 audit issue with the IRS as well as 2015 tax return adjustments recorded in 2016 related to the disposition of AEP's commercial barging operations.

FINANCIAL CONDITION

AEP measures financial condition by the strength of its balance sheet and the liquidity provided by its cash flows.

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	December 31,			
	2018		2017	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 23,346.7	52.7%	$ 21,173.3	51.5%
Short-term Debt	1,910.0	4.3	1,638.6	4.0
Total Debt	25,256.7	57.0	22,811.9	55.5
AEP Common Equity	19,028.4	42.9	18,287.0	44.4
Noncontrolling Interests	31.0	0.1	26.6	0.1
Total Debt and Equity Capitalization	$ 44,316.1	100.0%	$ 41,125.5	100.0%

AEP's ratio of debt-to-total capital increased from 55.5% as of December 31, 2017 to 57.0% as of December 31, 2018 primarily due to an increase in debt to support increased distribution and transmission investments.

Liquidity

Liquidity, or access to cash, is an important factor in determining AEP's financial stability. Management believes AEP has adequate liquidity under its existing credit facilities. As of December 31, 2018, AEP had a $4 billion revolving credit facility to support its commercial paper program. Additional liquidity is available from cash from operations and a receivables securitization agreement. Management is committed to maintaining adequate liquidity. AEP generally uses short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, sale-and-leaseback or leasing agreements or common stock.

Net Available Liquidity

AEP manages liquidity by maintaining adequate external financing commitments. As of December 31, 2018, available liquidity was $3.1 billion as illustrated in the table below:

	Amount	Maturity
	(in millions)	
Commercial Paper Backup:		
Revolving Credit Facility	$ 4,000.0	June 2022
Cash and Cash Equivalents	234.1	
Total Liquidity Sources	4,234.1	
Less: AEP Commercial Paper Outstanding	1,160.0	
Net Available Liquidity	$ 3,074.1	

AEP uses its commercial paper program to meet the short-term borrowing needs of its subsidiaries. The program funds a Utility Money Pool, which funds AEP's utility subsidiaries; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and the short-term debt requirements of subsidiaries that are not participating in either money pool for regulatory or operational reasons, as direct borrowers. The maximum amount of commercial paper outstanding during 2018 was $2.3 billion. The weighted-average interest rate for AEP's commercial paper during 2018 was 2.33%.

Other Credit Facilities

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of subsidiaries under four uncommitted facilities totaling $305 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of December 31, 2018, were $61 million with maturities ranging from January 2019 to December 2019.

Financing Plan

As of December 31, 2018, AEP had $1.7 billion of long-term debt due within one year. This included $457 million of Pollution Control Bonds with mandatory tender dates and credit support for variable interest rates that requires the debt be classified as current and $400 million of securitization bonds and DCC Fuel notes. Management plans to refinance the majority of the other maturities due within one year on a long-term basis.

Securitized Accounts Receivables

AEP receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and includes a $125 million and a $625 million facility which expire in July 2020 and 2021, respectively.

Debt Covenants and Borrowing Limitations

AEP's credit agreements contain certain covenants and require it to maintain a percentage of debt-to-total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in AEP's credit agreements. Debt as defined in the revolving credit agreements excludes securitization bonds and debt of AEP Credit. As of December 31, 2018, this contractually-defined percentage was 55.4%. Non-performance under these covenants could result in an event of default under these credit agreements. In addition, the acceleration of AEP's payment obligations, or the obligations of certain of AEP's major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements. This condition also applies in a majority of AEP's non-exchange traded commodity contracts and would similarly allow lenders and counterparties to declare the outstanding amounts payable. However, a default under AEP's non-exchange traded commodity contracts would not cause an event of default under its credit agreements.

The revolving credit facility does not permit the lenders to refuse a draw on any facility if a material adverse change occurs.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders and AEP manages its borrowings to stay within those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.67 per share in January 2019. Future dividends may vary depending upon AEP's profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends. Management does not believe these restrictions will have any significant impact on its ability to access cash to meet the payment of dividends on its common stock. See "Dividend Restrictions" section of Note 14 for additional information.

Credit Ratings

AEP and its utility subsidiaries do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit downgrade, but its access to the commercial paper market may depend on its credit ratings. In addition, downgrades in AEP's credit ratings by one of the rating agencies could increase its borrowing costs. Counterparty concerns about the credit quality of AEP or its utility subsidiaries could subject AEP to additional collateral demands under adequate assurance clauses under its derivative and non-derivative energy contracts.

CASH FLOW

AEP relies primarily on cash flows from operations, debt issuances and its existing cash and cash equivalents to fund its liquidity and investing activities. AEP's investing and capital requirements are primarily capital expenditures, repaying of long-term debt and paying dividends to shareholders. AEP uses short-term debt, including commercial paper, as a bridge to long-term debt financing. The levels of borrowing may vary significantly due to the timing of long-term debt financings and the impact of fluctuations in cash flows.

	Years Ended December 31, 2018	2017	2016
	(in millions)		
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$ 412.6	$ 403.5	$ 426.9
Net Cash Flows from Continuing Operating Activities	5,223.2	4,270.4	4,521.8
Net Cash Flows Used for Continuing Investing Activities	(6,353.6)	(3,656.4)	(5,046.6)
Net Cash Flows from (Used for) Continuing Financing Activities	1,161.9	(604.9)	503.9
Net Cash Flows from (Used for) Discontinued Operations	—	—	(2.5)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	31.5	9.1	(23.4)
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 444.1	$ 412.6	$ 403.5

Operating Activities

	Years Ended December 31, 2018	2017	2016
	(in millions)		
Income from Continuing Operations	$ 1,931.3	$ 1,928.9	$ 620.5
Non-Cash Adjustments to Income from Continuing Operations (a)	2,400.0	2,822.6	4,217.1
Mark-to-Market of Risk Management Contracts	(66.4)	(23.3)	150.8
Pension Contributions to Qualified Plant Trust	—	(93.3)	(84.8)
Property Taxes	(59.1)	(29.5)	(19.0)
Deferred Fuel Over/Under Recovery, Net	189.7	84.4	(65.5)
Recovery of Ohio Capacity Costs, Net	67.7	83.2	88.1
Provision for Refund - Global Settlement, Net	(5.5)	(98.2)	120.3
Disposition of Tanners Creek Plant Site	—	—	(93.5)
Change in Other Noncurrent Assets	119.8	(423.9)	(454.6)
Change in Other Noncurrent Liabilities	129.0	181.7	15.4
Change in Certain Components of Continuing Working Capital	516.7	(162.2)	27.0
Net Cash Flows from Continuing Operating Activities	$ 5,223.2	$ 4,270.4	$ 4,521.8

(a) Non-Cash Adjustments to Income from Continuing Operations includes Depreciation and Amortization, Deferred Income Taxes, Asset Impairments and Other Related Charges, Allowance for Equity Funds Used During Construction, Amortization of Nuclear Fuel, Pension and Postemployment Benefit Reserves, and Gain on Sale of Merchant Generation Assets.

2018 Compared to 2017

Net Cash Flows from Continuing Operating Activities increased by $953 million primarily due to the following:

- A $679 million increase in cash from Changes in Certain Components of Continuing Working Capital. This increase is primarily due to lower employee-related payments, increased accrued taxes, increased provisions for refund related to Tax Reform and timing of receivables and payables.
- A $544 million increase in Noncurrent Assets primarily due to changes in regulatory assets as a result of fewer storm deferrals, the impact of the FERC settlement on regulated AEP subsidiaries with rider recovery mechanisms in addition to the settlement of certain regulatory assets as a result of Ohio and West Virginia jurisdictional orders related to Tax Reform. See Note 4 - Rate Matters for additional information.
- A $105 million increase in cash from Deferred Fuel Over/Under Recovery, Net primarily due to fluctuations of fuel and purchase power costs at PSO and I&M and the reduction of ENEC balances at APCo and WPCo as a result of the West Virginia Tax Reform Order. See Note 4 - Rate Matters for additional information relating to the reduction of ENEC balances.
- A $93 million increase in cash due to refunds to customers in 2017 as a result of the 2016 Global Settlement in Ohio.
- A $93 million increase in cash due to Pension Contributions to Qualified Plan Trust in 2017 not made in 2018.

These increases in cash were partially offset by:

- A $420 million decrease in cash from Income from Continuing Operations, after non-cash adjustments. See Results of Operations for further detail.

2017 Compared to 2016

Net Cash Flows from Continuing Operating Activities decreased by $251 million primarily due to the following:

- A $189 million decrease in cash from Changes in Certain Components of Continuing Working Capital. This decrease in cash is primarily due to higher employee-related payments and increased revenue refunds.
- A $98 million decrease in cash due to refunds to customers as a result of the 2016 Global Settlement in Ohio.
- An $86 million decrease in cash from Income from Continuing Operations, after non-cash adjustments. See Results of Operations for further detail.

These decreases in cash were partially offset by:

- A $150 million increase in cash from Deferred Fuel Over/Under Recovery, Net. The increase in cash is primarily due to fluctuations of fuel and purchase power costs at PSO and collections in the Ohio Phase-in-Recovery Rider.

Investing Activities

	Years Ended December 31,		
	2018	2017	2016
	(in millions)		
Construction Expenditures	$ (6,310.9)	$ (5,691.3)	$ (4,781.1)
Acquisitions of Nuclear Fuel	(46.1)	(108.0)	(128.5)
Acquisitions of Assets/Businesses	(14.6)	(6.8)	(107.9)
Proceeds from Sale of Merchant Generation Assets	—	2,159.6	—
Other	18.0	(9.9)	(29.1)
Net Cash Flows Used for Continuing Investing Activities	$ (6,353.6)	$ (3,656.4)	$ (5,046.6)

2018 Compared to 2017

Net Cash Flows Used for Continuing Investing Activities increased by $2.7 billion primarily due to the following:

- A $2.2 billion decrease in cash due to the sale of certain merchant generation assets in 2017. See Note 7 - Dispositions and Impairments for additional information.
- A $620 million decrease in cash due to increased construction expenditures, primarily due to increases in Transmission and Distribution Utilities of $598 million.

These increases in cash were partially offset by:

- $62 million increase in cash due to reduced nuclear fuel purchases. The reduction in purchases is primarily due to variations from year to year in the timing and pricing of fuel reload requirements, material and services deliveries and the timing of cash payments during the nuclear fuel cycle.

2017 Compared to 2016

Net Cash Flows Used for Continuing Investing Activities decreased by $1.4 billion primarily due to the following:

- A $2.2 billion increase in cash due to the sale of certain merchant generation assets in 2017. See Note 7 - Dispositions and Impairments for additional information.
- A $101 million increase in cash primarily due to lower cost of acquisitions in 2017.
- A $21 million increase in cash due to reduced nuclear fuel purchases. Reduction in purchases is primarily due to variations from year to year in the timing and pricing of fuel reload requirements, material and services deliveries, and the timing of cash payments during the nuclear fuel cycle.

These increases in cash were partially offset by:

- A $910 million decrease in cash due to increased construction expenditures, primarily due to increases in Transmission and Distribution Utilities of $499 million, AEP Transmission Holdco of $275 million and Generation & Marketing of $95 million.

Financing Activities

	Years Ended December 31,		
	2018	2017	2016
		(in millions)	
Issuance of Common Stock	$ 73.6	$ 12.2	$ 34.2
Issuance/Retirement of Debt, Net	2,435.1	691.8	1,713.0
Dividends Paid on Common Stock	(1,255.5)	(1,191.9)	(1,121.0)
Other	(91.3)	(117.0)	(122.3)
Net Cash Flows from (Used for) Continuing Financing Activities	$ 1,161.9	$ (604.9)	$ 503.9

2018 Compared to 2017

Net Cash Flows from Continuing Financing Activities increased by $1.8 billion primarily due to the following:

- A $1.1 billion increase in cash due to increased issuances of long-term debt. See Note 14 - Financing Activities for additional information.
- A $346 million increase in cash from short-term debt primarily due to increased borrowings of commercial paper. See Note 14 - Financing Activities for additional information.
- A $306 million increase in cash due to decreased retirements of long-term debt. See Note 14 - Financing Activities for additional information.
- A $61 million increase in cash due to increased proceeds from issuances of common stock.

These increases in cash were partially offset by:

- A $64 million decrease in cash due to increased common stock dividend payments primarily due to increased dividends per share from 2017 to 2018.

2017 Compared to 2016

Net Cash Flows Used for Continuing Financing Activities increased by $1.1 billion primarily due to the following:

- A $1.3 billion decrease in cash due to increased retirements of long-term debt. See Note 14 - Financing Activities for additional information.
- A $987 million decrease in cash from short-term debt primarily due to increased repayments of commercial paper. See Note 14 - Financing Activities for additional information.
- A $71 million decrease in cash due to increased common stock dividend payments primarily due to increased dividends per share from 2016 to 2017.
- A $22 million decrease in cash due to reduced proceeds from issuances of common stock.

These decreases in cash were partially offset by:

- A $1.3 billion increase in cash due to increased issuances of long-term debt. See Note 14 - Financing Activities for additional information.

The following financing activities occurred during 2018:

AEP Common Stock:

- During 2018, AEP issued 1.2 million shares of common stock under the incentive compensation, employee saving and dividend reinvestment plans and received net proceeds of $74 million.

Debt:

- During 2018, AEP issued approximately $5 billion of long-term debt, including $4.1 billion of senior unsecured notes at interest rates ranging from 3.65% to 4.3%, $369 million of pollution control bonds at interest rates ranging from 2.625% to 3.05% and $550 million of other debt at variable interest rates. The proceeds from these issuances were used to fund long-term debt maturities and construction programs.
- During 2018, AEP entered into and settled $300 million of notional interest rate derivatives that were designated as cash flow hedges. The settlement of interest rate derivatives in 2018 resulted in net cash received of $4 million. As of December 31, 2018, AEP had $500 million of notional interest rate derivatives remaining that were designated as fair value hedges.

In 2019:

In January and February 2019, I&M retired $15 million and $2 million, respectively, of Notes Payable related to DCC Fuel.

In January and February 2019, Transource Energy issued $3 million and $3 million, respectively, of variable rate Other Long-term Debt due in 2020.

In January 2019, AEP Texas retired $104 million of Securitization Bonds.

In January 2019, OPCo retired $23 million of Securitization Bonds.

In January 2019, SWEPCo retired $54 million of 1.60% Pollution Control Bonds due in 2019.

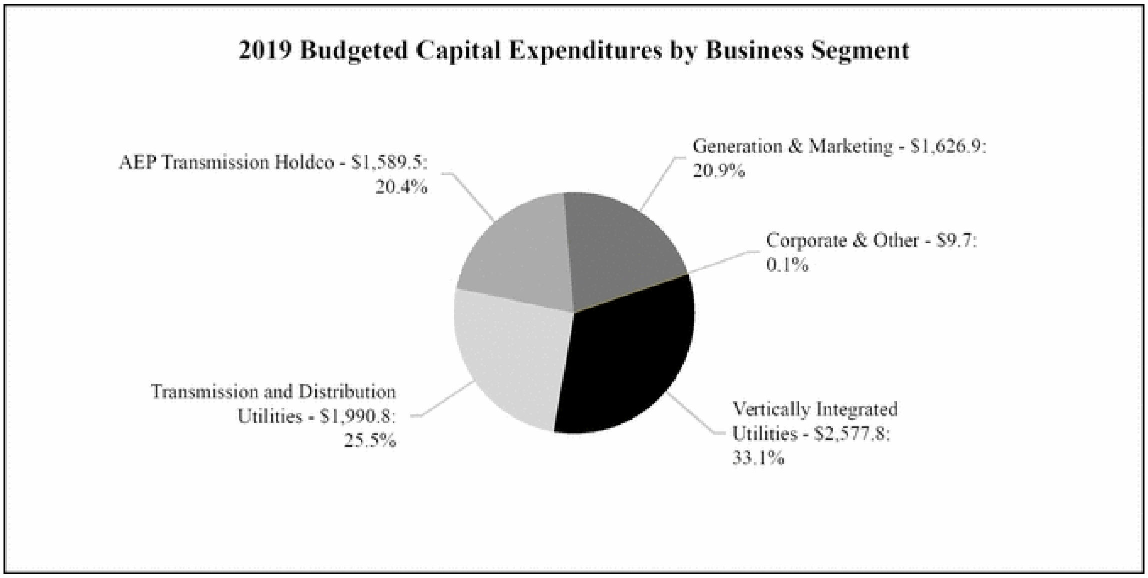
In February 2019, APCo retired $12 million of Securitization Bonds.

BUDGETED CAPITAL EXPENDITURES

Management forecasts approximately $7.8 billion of capital expenditures in 2019. For the four year period, 2020 through 2023, management forecasts capital expenditures of $25.1 billion. The expenditures are generally for transmission, generation, distribution, regulated and contracted renewables, and required environmental investment to comply with the Federal EPA rules. Estimated capital expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. Management expects to fund these capital expenditures through cash flows from operations and financing activities. Generally, the Registrant Subsidiaries use cash or short-term borrowings under the money pool to fund these expenditures until long-term funding is arranged. The 2019 estimated capital expenditures include generation, transmission and distribution related investments, as well as expenditures for compliance with environmental regulations as follows:

Segment	2019 Budgeted Capital Expenditures					
	Environmental	Generation	Transmission	Distribution	Other (a)	Total
			(in millions)			
Vertically Integrated Utilities	$ 222.7	$ 383.1	$ 727.1	$ 972.3	$ 272.6	$ 2,577.8
Transmission and Distribution Utilities	0.1	2.4	994.1	781.1	213.1	1,990.8
AEP Transmission Holdco	—	—	1,546.4	—	43.1	1,589.5
Generation & Marketing	15.0	1,557.6 (b)	—	—	54.3	1,626.9
Corporate and Other	—	—	—	—	9.7	9.7
Total	$ 237.8	$ 1,943.1	$ 3,267.6	$ 1,753.4	$ 592.8	$ 7,794.7

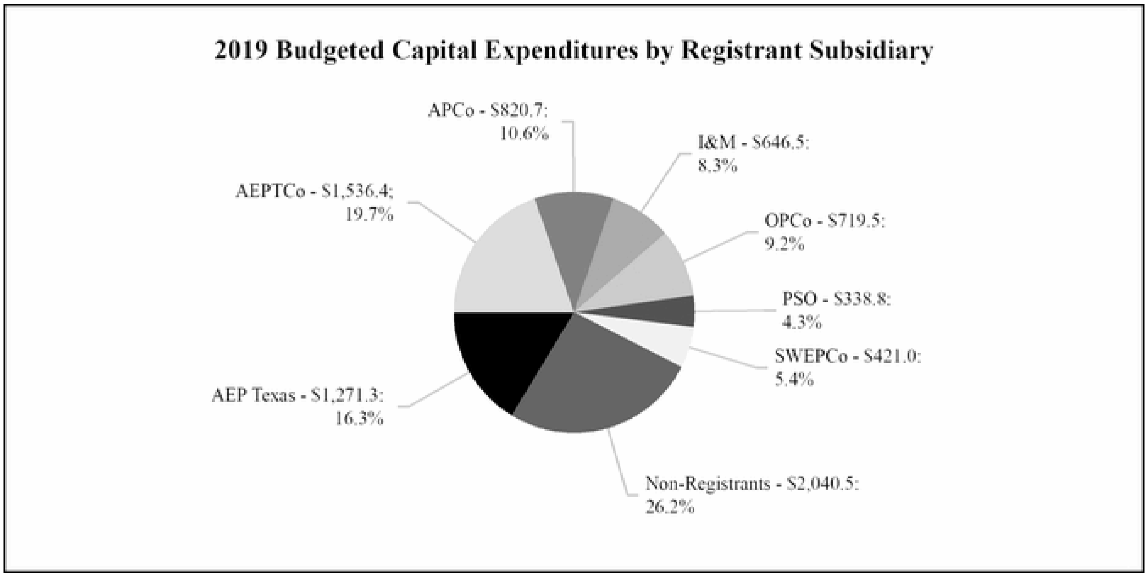
(a) Amount primarily consists of facilities, software and telecommunications.
(b) Amount includes $1.1 billion for the acquisition of Sempra Renewables LLC, which includes 724 MWs of wind generation and battery assets and is funded through $551 million in cash, assumption of $343 million of existing project debt obligations of the non-consolidated joint ventures and recognition of non-controlling tax equity interest of $162 million.



The 2019 estimated capital expenditures by Registrant Subsidiary include distribution, transmission and generation related investments, as well as expenditures for compliance with environmental regulations as follows:

	2019 Budgeted Capital Expenditures					
Company	Environmental	Generation	Transmission	Distribution	Other (a)	Total
			(in millions)			
AEP Texas	$ 0.1	$ 2.4	$ 785.4	$ 374.1	$ 109.3	$ 1,271.3
AEPTCo	—	—	1,496.6	—	39.8	1,536.4
APCo	32.7	83.5	309.8	304.2	90.5	820.7
I&M	76.8	179.8	96.5	229.8	63.6	646.5
OPCo	—	—	208.7	407.0	103.8	719.5
PSO	2.5	31.1	62.7	194.2	48.3	338.8
SWEPCo	25.1	57.7	150.7	135.4	52.1	421.0

(a) Amount primarily consists of facilities, software and telecommunications.



OFF-BALANCE SHEET ARRANGEMENTS

AEP's current guidelines restrict the use of off-balance sheet financing entities or structures to traditional operating lease arrangements that AEP enters in the normal course of business. The following identifies significant off-balance sheet arrangements.

Rockport Plant, Unit 2

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant, Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for AEGCo and I&M were $295 million each as of December 31, 2018.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. AEP's subsidiaries account for the lease as an operating lease with the future payment obligations included in Note 13 - Leases. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. AEP, as well as AEP's subsidiaries, have no ownership interest in the Owner Trustee and do not guarantee its debt. See "Rockport Plant Litigation" section of Note 6 for additional information.

CONTRACTUAL OBLIGATION INFORMATION

AEP's contractual cash obligations include amounts reported on the balance sheets and other obligations disclosed in the footnotes. The following table summarizes AEP's contractual cash obligations as of December 31, 2018 and does not reflect AEP's planned 2019 acquisition of Sempra Renewables, LLC. See "Other Renewable Generation" section of Executive Overview for additional information.

Payments Due by Period

Contractual Cash Obligations	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Short-term Debt (a)	$ 1,910.0	$ —	$ —	$ —	$ 1,910.0
Interest on Fixed Rate Portion of Long-term Debt (b)	1,030.3	1,955.9	1,719.2	11,189.0	15,894.4
Fixed Rate Portion of Long-term Debt (c)	924.4	2,800.0	2,128.2	16,150.9	22,003.5
Variable Rate Portion of Long-term Debt (d)	774.1	669.8	79.8	—	1,523.7
Capital Lease Obligations (e)	70.8	111.9	79.3	90.2	352.2
Noncancelable Operating Leases (e)	259.6	482.8	280.8	165.2	1,188.4
Fuel Purchase Contracts (f)	1,108.4	1,075.9	381.0	147.0	2,712.3
Energy and Capacity Purchase Contracts	239.7	463.6	324.3	1,337.2	2,364.8
Construction Contracts for Capital Assets (g)	2,429.1	3,127.6	1,679.9	3,245.0	10,481.6
Total	$ 8,746.4	$ 10,687.5	$ 6,672.5	$ 32,324.5	$ 58,430.9

(a) Represents principal only, excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2018 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See "Long-term Debt" section of Note 14. Represents principal only, excluding interest.
(d) See "Long-term Debt" section of Note 14. Represents principal only, excluding interest. Variable rate debt had interest rates that ranged between 1.66% and 3.94% as of December 31, 2018.
(e) See Note 13 - Leases.
(f) Represents contractual obligations to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.
(g) Represents only capital assets for which there are signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

AEP's $18 million liability related to uncertain tax positions is not included above because management cannot reasonably estimate the cash flows by period.

AEP's pension funding requirements are not included in the above table. As of December 31, 2018, AEP expects to make contributions to the pension plans totaling $99 million in 2019. Estimated contributions of $105 million in 2020 and $108 million in 2021 may vary significantly based on market returns, changes in actuarial assumptions and other factors. Based upon the projected benefit obligation and fair value of assets available to pay pension benefits, the pension plans were 97.6% funded as of December 31, 2018. See "Estimated Future Benefit Payments and Contributions" section of Note 8.

In addition to the amounts disclosed in the contractual cash obligations table above, additional commitments are made in the normal course of business. These commitments include standby letters of credit, guarantees for the payment of obligation performance bonds and other commitments. As of December 31, 2018, the commitments outstanding under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period

Other Commercial Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Standby Letters of Credit (a)	$ 60.6	$ —	$ —	$ —	$ 60.6
Guarantees of the Performance of Outside Parties (b)	—	—	—	140.0	140.0
Guarantees of Performance (c)	1,526.6	—	—	—	1,526.6
Total Commercial Commitments	$ 1,587.2	$ —	$ —	$ 140.0	$ 1,727.2

(a) Standby letters of credit are entered into with third-parties. These letters of credit are issued in the ordinary course of business and cover items such as natural gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves. There is no collateral held in relation to any guarantees in excess of the ownership percentages. In the event any letters of credit are drawn, there is no recourse to third-parties. See “Letters of Credit” section of Note 6.
(b) See “Guarantees of Third-Party Obligations” section of Note 6.
(c) Performance guarantees and indemnifications issued for energy trading and various sale agreements.

SIGNIFICANT TAX LEGISLATION

In December 2017, Tax Reform legislation was signed into law. Tax Reform includes significant changes to the Internal Revenue Code of 1986, as amended, including lowering the corporate federal income tax rate from 35% to 21%. As a result of this rate change, the Registrants’ deferred tax assets and liabilities were remeasured using the newly enacted rate of 21% in December 2017. In response to Tax Reform, the SEC staff issued Staff Accounting Bulletin 118 (SAB 118) in December 2017. SAB 118 provided for up to a one year period (the measurement period) in which to complete the required analyses and accounting required by Tax Reform.

During 2017, AEP recorded provisional amounts for the income tax effects of Tax Reform. Throughout 2018, AEP continued to assess the impacts of legislative changes in the tax code as well as interpretative changes of the tax code. The measurement period adjustments recorded during 2018 were immaterial.

The measurement period under SAB 118 ended in December 2018. However, Tax Reform uncertainties still remain and AEP will continue to monitor income tax effects that may change as a result of future legislation and further interpretation of Tax Reform based on proposed U.S. Treasury regulations and guidance from the IRS and state tax authorities.

The IRS has proposed new regulations that provide guidance regarding the additional first-year depreciation deduction under Section 168(k). The proposed regulations reflect changes as a result of Tax Reform and affect taxpayers with qualified depreciable property acquired and placed in service after September 27, 2017. Generally, AEP’s regulated utilities will not be eligible for any bonus depreciation for property acquired and placed in service after January 1, 2018 and AEP’s competitive businesses will be eligible for 100% expensing. However, for self-constructed property and other property placed in service in 2018 for which construction began prior to January 1, 2018, taxpayers are required to evaluate the contractual terms to determine if these additions qualify for 100% expensing under Tax Reform or 50% bonus depreciation as provided under prior tax law.

During the fourth quarter of 2018, the IRS proposed new regulations that reflect changes as a result of Tax Reform concerning potential limitations on the deduction of business interest expense. These regulations require an allocation of net interest expense between regulated and competitive businesses within the consolidated tax return. This allocation is based upon net tax basis, and the proposed regulations provide a de minimis test under which all interest is deductible if less than 10% is allocable to the competitive businesses. Management continues to review and evaluate the proposed regulations and at this time expect to be able to deduct materially all business interest expense under this de minimis provision.

Section 162(m) of the Internal Revenue Code generally limits the amount of compensation a company can deduct annually to $1 million for certain executive officers. The exemption from Section 162(m)'s deduction limit for performance-based compensation was repealed by Tax Reform, effective for taxable years ending after December 31, 2017. Management continues to evaluate whether any of its compensation plans qualify for transitional relief, such that payments made pursuant to these plans might be deductible.

CYBER SECURITY

The electric utility industry is an identified critical infrastructure function with mandatory cyber security requirements under the authority of FERC. The North American Electric Reliability Corporation (NERC), which FERC certified as the nation's Electric Reliability Organization, developed mandatory critical infrastructure protection cyber security reliability standards. AEP began participating in the NERC grid security and emergency response exercises, GridEx, in 2013 and continues to participate in the bi-yearly exercises. These efforts, led by NERC, test and further develop the coordination, threat sharing and interaction between utilities and various government agencies relative to potential cyber and physical threats against the nation's electric grid. The operations of AEP's electric utility subsidiaries are subject to extensive and rigorous mandatory cyber and physical security requirements that are developed and enforced by NERC to protect grid security and reliability. AEP's Enterprise Security program uses the National Institute of Standards and Technology Cybersecurity Framework as a guideline.

Critical cyber assets, such as data centers, power plants, transmission operations centers and business networks are protected using multiple layers of cyber security and authentication. Cyber hackers have been successful in breaching a number of very secure facilities, including federal agencies, banks and retailers. As understanding of these events develop, AEP has adopted a defense in depth approach to cyber security and continually assesses its cyber security tools and processes to determine where to strengthen its defenses. These strategies include monitoring, alerting and emergency response, forensic analysis, disaster recovery and criminal activity reporting. This approach allows AEP to deal with threats in real time.

AEP has undertaken a variety of actions to monitor and address cyber related risks. Cyber security and the effectiveness of AEP's cyber security processes are reviewed annually with the Board of Directors and at several meetings with the Audit Committee throughout the year. AEP's strategy for managing cyber related risks is integrated within its enterprise risk management processes. AEP enterprise security continually adjusts staff and resources in response to the evolving threat landscape. In addition, AEP maintains cyber liability insurance to cover certain damages caused by cyber incidents.

AEP's Chief Security Officer (CSO) leads the cyber security and physical security teams and is responsible for the design, implementation and execution of AEP's security risk management strategy, which includes cyber security. AEP operates a 24/7 Cyber Security Intelligence and Response Center (cyber security team) responsible for monitoring the AEP System for cyber risks and threats. Among other things, the CSO and the cyber security team actively monitor best practices, perform penetration testing, lead response exercises and internal campaigns and provide training and communication across the organization.

The cyber security team constantly scans the AEP System for risks and threats. AEP also continually reviews its business continuity plan to develop an effective recovery strategy that seeks to decrease response times, limit financial impacts and maintain customer confidence during any business interruption. AEP has implemented a third-party risk governance program to identify potential risks introduced through third-party relationships, such as vendors, software and hardware manufacturers or professional service providers. As warranted, AEP obtains certain contractual security guarantees and assurances with these third-party relationships to help ensure the security and safety of our information. The cyber security team works closely with a broad range of departments, including legal, regulatory, corporate communications and audit services and information technology.

The cyber security team collaborates with partners from both industry and government, and routinely participates in industry-wide programs that exchange knowledge of threats with utility peers, industry and federal agencies. AEP is an active member of a number of industry specific threat and information sharing communities including the Department of Homeland Security and the Electricity Information Sharing and Analysis Center. AEP continues to work with nonaffiliated entities to do penetration testing and to design and implement appropriate remediation strategies.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. Management considers an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates that could have been selected could have a material effect on net income or financial condition.

Management discusses the development and selection of critical accounting estimates as presented below with the Audit Committee of AEP's Board of Directors and the Audit Committee reviews the disclosures relating to them.

Management believes that the current assumptions and other considerations used to estimate amounts reflected in the financial statements are appropriate. However, actual results can differ significantly from those estimates.

The sections that follow present information about critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required

The Registrants' financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated.

The Registrants recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, the timing of expense and income recognition is matched with regulated revenues. Liabilities are also recorded for refunds, or probable refunds, to customers that have not been made.

Assumptions and Approach Used

When incurred costs are probable of recovery through regulated rates, regulatory assets are recorded on the balance sheet. Management reviews the probability of recovery at each balance sheet date and whenever new events occur. Similarly, regulatory liabilities are recorded when a determination is made that a refund is probable or when ordered by a commission. Examples of new events that affect probability include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs as well as the return of revenues, rate of return earned on invested capital and timing and amount of assets to be recovered through regulated rates. If recovery of a regulatory asset is no longer probable, that regulatory asset is written-off as a charge against earnings. A write-off of regulatory assets or establishment of a regulatory liability may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used

A change in the above assumptions may result in a material impact on net income. Refer to Note 5 - Effects of Regulation for further detail related to regulatory assets and regulatory liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required

AEP recognizes revenues from customers as the performance obligations of delivering energy to customers are satisfied. The determination of sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is recorded. This estimate is reversed in the following month and actual revenue is recorded based on meter readings. PSO and SWEPCo do not include the fuel portion in unbilled revenue in accordance with the applicable state commission regulatory treatment in Arkansas, Louisiana, Oklahoma and Texas.

Accrued unbilled revenues for the Vertically Integrated Utilities segment were $255 million and $278 million as of December 31, 2018 and 2017, respectively. The changes in unbilled electric utility revenues for AEP's Vertically Integrated Utilities segment were $(23) million, $37 million and $50 million for the years ended December 31, 2018, 2017 and 2016, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rates.

Accrued unbilled revenues for the Transmission and Distribution Utilities segment were $178 million and $202 million as of December 31, 2018 and 2017, respectively. The changes in unbilled electric utility revenues for AEP's Transmission and Distribution Utilities segment were $(24) million, $11 million and $40 million for the years ended December 31, 2018, 2017 and 2016, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rates.

Accrued unbilled revenues for the Generation & Marketing segment were $59 million and $54 million as of December 31, 2018 and 2017, respectively. The changes in unbilled electric utility revenues for AEP's Generation & Marketing segment were $5 million, $5 million and $2 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Assumptions and Approach Used

For each Registrant except AEPTCo, the monthly estimate for unbilled revenues is based upon a primary computation of net generation (generation plus purchases less sales) less the current month's billed KWh and estimated line losses, plus the prior month's unbilled KWh. However, due to the potential for meter reading issues, meter drift and other anomalies, a secondary computation is made, based upon an allocation of billed KWh to the current month and previous month, on a billing cycle-by-cycle basis, and by dividing the current month aggregated result by the billed KWh. The two methodologies are evaluated to confirm that they are not statistically different.

For AEP's Generation & Marketing segment, management calculates unbilled revenues by contract using the most recent historic daily activity adjusted for significant known changes in usage.

Effect if Different Assumptions Used

If the two methodologies used to estimate unbilled revenue are statistically different, a limiter adjustment is made to bring the primary computation within one standard deviation of the secondary computation. Additionally, significant fluctuations in energy demand for the unbilled period, weather, line losses or changes in the composition of customer classes could impact the estimate of unbilled revenue.

Accounting for Derivative Instruments

Nature of Estimates Required

Management considers fair value techniques, valuation adjustments related to credit and liquidity and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used

The Registrants measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based primarily on exchange prices and broker quotes. If a quoted market price is not available, the fair value is estimated based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

The Registrants reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. Liquidity adjustments are calculated by utilizing bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. Credit adjustments on risk management contracts are calculated using estimated default probabilities and recovery rates relative to the counterparties or counterparties with similar credit profiles and contractual netting agreements.

With respect to hedge accounting, management assesses hedge effectiveness and evaluates a forecasted transaction's probability of occurrence within the specified time period as provided in the original hedge documentation.

Effect if Different Assumptions Used

There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts settle.

The probability that hedged forecasted transactions will not occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified into operating income.

For additional information regarding derivatives, hedging and fair value measurements, see Note 10 - Derivatives and Hedging and Note 11 - Fair Value Measurements. See "Fair Value Measurements of Assets and Liabilities" section of Note 1 for AEP's fair value calculation policy.

Long-Lived Assets

Nature of Estimates Required

In accordance with the requirements of "Property, Plant and Equipment" accounting guidance and "Regulated Operations" accounting guidance, the Registrants evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable. Such events or changes in circumstance include planned abandonments, probable disallowances for rate-making purposes of assets determined to be recently completed plant and assets that meet the held-for-sale criteria. The Registrants utilize a group composite method of depreciation to estimate the useful lives of long-lived assets.

An impairment evaluation of a long-lived, held and used asset may result from an abandonment, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the carrying amount of the asset is not recoverable, the Registrants record an impairment to the extent that the fair value of the asset is less than its book value. Performing an impairment evaluation involves a significant degree of estimation and judgment in areas such as identifying circumstances that indicate an impairment may exist, identifying and grouping affected assets and developing the undiscounted and discounted future cash flows (used to estimate fair value in the absence of market-based value, in some instances) associated with the asset. For assets held for sale, an impairment is recognized if the expected net sales price is less than its book value. Any impairment charge is recorded as a reduction to earnings.

Assumptions and Approach Used

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, the Registrants estimate fair value using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales or independent appraisals. Cash flow estimates are based on relevant information available at the time the estimates are made. Estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results. Also, when measuring fair value, management evaluates the characteristics of the asset or liability to determine if market participants would take those characteristics into account when pricing the asset or liability at the measurement date. Such characteristics include, for example, the condition and location of the asset or restrictions on the use of the asset. The Registrants perform depreciation studies that include a review of any external factors that may affect the useful life to determine composite depreciation rates and related lives which are subject to periodic review by state regulatory commissions for regulated assets. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used

In connection with the evaluation of long-lived assets in accordance with the requirements of "Property, Plant and Equipment" accounting guidance, the fair value of the asset can vary if different estimates and assumptions are used in the applied valuation techniques. Estimates for depreciation rates contemplate the history of interim capital replacements and the amount of salvage expected. In cases of impairment, the best estimate of fair value was made using valuation methods based on the most current information at that time. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, the timing and terms of the transactions and management's analysis of the benefits of the transaction.

Pension and OPEB

AEP maintains a qualified, defined benefit pension plan (Qualified Plan), which covers substantially all nonunion and certain union employees, and unfunded, nonqualified supplemental plans (Nonqualified Plans) to provide benefits in excess of amounts permitted under the provisions of the tax law for participants in the Qualified Plan (collectively the Pension Plans). Additionally, AEP entered into individual employment contracts with certain current and retired executives that provide additional retirement benefits as a part of the Nonqualified Plans. AEP also sponsors OPEB plans to provide health and life insurance benefits for retired employees. The Pension Plans and OPEB plans are collectively referred to as the Plans.

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see “Investments Held in Trust for Future Liabilities” and “Fair Value Measurements of Assets and Liabilities” sections of Note 1. See Note 8 - Benefit Plans for information regarding costs and assumptions for the Plans.

The following table shows the net periodic cost (credit) of the Plans:

Net Periodic Cost (Credit)	Years Ended December 31, 2018	2017	2016
	(in millions)		
Pension Plans	$ 82.9	$ 98.6	$ 103.2
OPEB	(101.8)	(63.2)	(73.5)

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including expected long-term rates of return on the Plans’ assets. In developing the expected long-term rate of return assumption for 2019, management evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Management also considered historical returns of the investment markets and tax rates which affect a portion of the OPEB plans’ assets. Management anticipates that the investment managers employed for the Plans will invest the assets to generate future returns averaging 6.25% for the Qualified Plan and 6.25% for the OPEB plans.

The expected long-term rate of return on the Plans’ assets is based on management’s targeted asset allocation and expected investment returns for each investment category. Assumptions for the Plans are summarized in the following table:

	Pension Plans		OPEB	
	2019 Target Asset Allocation	Assumed/ Expected Long-Term Rate of Return	2019 Target Asset Allocation	Assumed/ Expected Long-Term Rate of Return
Equity	25%	8.25%	49%	7.48%
Fixed Income	59	4.90	49	5.08
Other Investments	15	8.31	—	—
Cash and Cash Equivalents	1	2.50	2	2.50
Total	100%		100%	

Management regularly reviews the actual asset allocation and periodically rebalances the investments to the targeted allocation. Management believes that 6.25% for both the Qualified Plan and OPEB plans are reasonable estimates of the long-term rate of return on the Plans’ assets. The Pension Plans’ assets had an actual loss of 2.10% for the year ended December 31, 2018 and an actual gain of 12.86% for the year ended December 31, 2017. The OPEB plans’ assets had an actual loss of 6.38% for the year ended December 31, 2018 and an actual gain of 18.38% for the year ended December 31, 2017. Management will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

AEP bases the determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2018, AEP had cumulative losses of approximately $173 million that remain to be recognized in the calculation of the market-related value of assets. These unrecognized market-related net actuarial losses may result in increases in the future pension costs depending on several factors, including whether such losses at each measurement date exceed the corridor in accordance with "Compensation – Retirement Benefits" accounting guidance.

The method used to determine the discount rate that AEP utilizes for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan. The discount rate as of December 31, 2018 under this method was 4.3% for the Qualified Plan, 4.2% for the Nonqualified Plans and 4.3% for the OPEB plans. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Pension Plans' assets of 6.25%, discount rates of 4.3% and 4.2% and various other assumptions, management estimates that the pension costs for the Pension Plans will approximate $57 million, $67 million and $62 million in 2019, 2020 and 2021, respectively. Based on an expected rate of return on the OPEB plans' assets of 6.25%, a discount rate of 4.3% and various other assumptions, management estimates OPEB plan credits will approximate $81 million, $81 million and $83 million in 2019, 2020 and 2021, respectively. Future actual costs will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in the "Effect if Different Assumptions Used" section below.

The value of AEP's Pension Plans' assets decreased to $4.7 billion as of December 31, 2018 from $5.2 billion as of December 31, 2017 primarily due to lower investment returns and benefit payments made in 2018. During 2018, the Qualified Plan paid $374 million and the Nonqualified Plans paid $11 million in benefits to plan participants. The value of AEP's OPEB plans' assets decreased to $1.5 billion as of December 31, 2018 from $1.7 billion as of December 31, 2017 primarily due to lower investment returns and benefit payments made in 2018. The OPEB plans paid $134 million in benefits to plan participants during 2018.

Nature of Estimates Required

AEP sponsors pension and OPEB plans in various forms covering all employees who meet eligibility requirements. These benefits are accounted for under "Compensation" and "Plan Accounting" accounting guidance. The measurement of pension and OPEB obligations, costs and liabilities is dependent on a variety of assumptions.

Assumptions and Approach Used

The critical assumptions used in developing the required estimates include the following key factors:

- Discount rate
- Compensation increase rate
- Cash balance crediting rate
- Health care cost trend rate
- Expected return on plan assets

Other assumptions, such as retirement, mortality and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used

The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. These differences may result in a significant impact to the amount of pension and OPEB expense recorded. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

	Pension Plans		OPEB	
	+0.5%	-0.5%	+0.5%	-0.5%
	(in millions)			
Effect on December 31, 2018 Benefit Obligations				
Discount Rate	$ (237.6)	$ 260.7	$ (59.4)	$ 65.3
Compensation Increase Rate	21.5	(19.7)	NA	NA
Cash Balance Crediting Rate	68.2	(63.3)	NA	NA
Health Care Cost Trend Rate	NA	NA	16.9	(15.7)
Effect on 2018 Periodic Cost				
Discount Rate	$ (13.4)	$ 14.6	$ (2.3)	$ 2.5
Compensation Increase Rate	5.6	(5.1)	NA	NA
Cash Balance Crediting Rate	14.3	(13.2)	NA	NA
Health Care Cost Trend Rate	NA	NA	2.1	(1.9)
Expected Return on Plan Assets	(24.2)	24.2	(8.5)	8.5

NA Not applicable.

ACCOUNTING PRONOUNCEMENTS

See Note 2 - New Accounting Pronouncements for information related to accounting pronouncements adopted in 2018 and pronouncements effective in the future.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

The Vertically Integrated Utilities segment is exposed to certain market risks as a major power producer and through transactions in power, coal, natural gas and marketing contracts. These risks include commodity price risks which may be subject to capacity risk, credit risk as well as interest rate risk. In addition, this segment is exposed to foreign currency exchange risk from occasionally procuring various services and materials used in its energy business from foreign suppliers. These risks represent the risk of loss that may impact this segment due to changes in the underlying market prices or rates.

The Transmission and Distribution Utilities segment is exposed to energy procurement risk and interest rate risk.

The Generation & Marketing segment conducts marketing, risk management and retail activities in ERCOT, PJM, SPP and MISO. This segment is exposed to certain market risks as a marketer of wholesale and retail electricity. These risks include commodity price risks which may be subject to capacity risk, credit risk as well as interest rate risk. These risks represent the risk of loss that may impact this segment due to changes in the underlying market prices or rates. In addition, the Generation & Marketing segment is also exposed to certain market risks as a power producer and through transactions in wholesale electricity, natural gas and marketing contracts.

Management employs risk management contracts including physical forward and financial forward purchase-and-sale contracts. Management engages in risk management of power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. As a result, AEP is subject to price risk. The amount of risk taken is determined by the Commercial Operations, Energy Supply and

Finance groups in accordance with established risk management policies as approved by the Finance Committee of the Board of Directors. AEPSC's market risk oversight staff independently monitors risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) and the Energy Supply Risk Committee (Competitive Risk Committee) various reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer. The Competitive Risk Committee consists of AEPSC's Chief Financial Officer and Chief Risk Officer in addition to Energy Supply's President and Vice President. When commercial activities exceed predetermined limits, positions are modified to reduce the risk to be within the limits unless specifically approved by the respective committee.

The following table summarizes the reasons for changes in total MTM value as compared to December 31, 2017:

MTM Risk Management Contract Net Assets (Liabilities)
Year Ended December 31, 2018

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
		(in millions)		
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2017	$ 42.1	$ (131.3)	$ 163.9	$ 74.7
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(30.1)	(5.4)	(20.1)	(55.6)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	11.7	11.7
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	9.0	9.0
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	78.9	35.7	—	114.6
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2018	$ 90.9	$ (101.0)	$ 164.5	154.4
Commodity Cash Flow Hedge Contracts				(24.8)
Fair Value Hedge Contracts				(17.4)
Collateral Deposits				(13.8)
Total MTM Derivative Contract Net Assets as of December 31, 2018				$ 98.4

(a) Reflects fair value on primarily long-term structured contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory liabilities/assets or accounts payable.

See Note 10 – Derivatives and Hedging and Note 11 – Fair Value Measurements for additional information related to risk management contracts. The following tables and discussion provide information on credit risk and market volatility risk.

Credit Risk

Credit risk is mitigated in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. Management uses credit agency ratings and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

AEP has risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, exposures change daily. As of December 31, 2018, credit exposure net of collateral to sub investment grade counterparties was approximately 6.4%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of December 31, 2018, the following table approximates AEP's counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
	(in millions, except number of counterparties)				
Investment Grade	$ 480.4	$ 2.2	$ 478.2	3	$ 260.1
Noninvestment Grade	1.5	1.5	—	—	—
No External Ratings:					
Internal Investment Grade	120.8	—	120.8	3	79.9
Internal Noninvestment Grade	51.2	10.5	40.7	2	28.7
Total as of December 31, 2018	$ 653.9	$ 14.2	$ 639.7		

In addition, AEP is exposed to credit risk related to participation in RTOs. For each of the RTOs in which AEP participates, this risk is generally determined based on the proportionate share of member gross activity over a specified period of time.

Value at Risk (VaR) Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates VaR, to measure AEP's commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of December 31, 2018, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

Management calculates the VaR for both a trading and non-trading portfolio. The trading portfolio consists primarily of contracts related to energy trading and marketing activities. The non-trading portfolio consists primarily of economic hedges of generation and retail supply activities. The following tables show the end, high, average and low market risk as measured by VaR for the periods indicated:

VaR Model
Trading Portfolio

Twelve Months Ended December 31, 2018				Twelve Months Ended December 31, 2017			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 1.1	$ 1.8	$ 0.3	$ 0.1	$ 0.2	$ 0.5	$ 0.2	$ 0.1

VaR Model
Non-Trading Portfolio

Twelve Months Ended December 31, 2018				Twelve Months Ended December 31, 2017			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 4.0	$ 16.5	$ 2.7	$ 0.4	$ 4.1	$ 6.5	$ 1.0	$ 0.3

Management back-tests VaR results against performance due to actual price movements. Based on the assumed 95% confidence interval, the performance due to actual price movements would be expected to exceed the VaR at least once every 20 trading days.

As the VaR calculation captures recent price movements, management also performs regular stress testing of the trading portfolio to understand AEP's exposure to extreme price movements. A historical-based method is employed whereby the current trading portfolio is subjected to actual, observed price movements from the last several years in order to ascertain which historical price movements translated into the largest potential MTM loss. Management then researches the underlying positions, price movements and market events that created the most significant exposure and reports the findings to the Risk Executive Committee, Regulated Risk Committee, or Competitive Risk Committee as appropriate.

Interest Rate Risk

AEP is exposed to interest rate market fluctuations in the normal course of business operations. AEP has outstanding short and long-term debt which is subject to a variable rate. AEP manages interest rate risk by limiting variable rate exposures to a percentage of total debt, by entering into interest rate derivative instruments and by monitoring the effects of market changes in interest rates. For the twelve months ended December 31, 2018, 2017 and 2016, a 100 basis point change in the benchmark rate on AEP's variable rate debt would impact pretax interest expense annually by $25 million, $28 million and $37 million, respectively.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
American Electric Power Company, Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and its subsidiaries (the "Company") as of December 31, 2018 and 2017, and the related consolidated statements of income, comprehensive income (loss), changes in equity, and cash flows for each of the two years in the period ended December 31, 2018, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 21, 2019

We have served as the Company's auditor since 2017.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
American Electric Power Company, Inc.:

We have audited the accompanying consolidated statements of income, comprehensive income (loss), changes in equity, and cash flows of American Electric Power Company, Inc. and subsidiary companies (the "Company") for the year ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the results of operations and cash flows of American Electric Power Company, Inc. and subsidiary companies for the year ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2017

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of American Electric Power Company, Inc. and Subsidiary Companies (AEP) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEP's internal control is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of AEP's internal control over financial reporting as of December 31, 2018. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded AEP's internal control over financial reporting was effective as of December 31, 2018.

PricewaterhouseCoopers LLP, AEP's independent registered public accounting firm has issued an audit report on the effectiveness of AEP's internal control over financial reporting as of December 31, 2018. The Report of Independent Registered Public Accounting Firm appears on the previous page.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2018, 2017 and 2016
(in millions, except per-share and share amounts)

	Years Ended December 31,		
	2018	2017	2016
REVENUES			
Vertically Integrated Utilities	$ 9,556.7	$ 9,095.1	$ 9,012.4
Transmission and Distribution Utilities	4,552.3	4,328.9	4,328.3
Generation & Marketing	1,818.1	1,771.4	2,858.7
Other Revenues	268.6	229.5	180.7
TOTAL REVENUES	16,195.7	15,424.9	16,380.1
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	2,359.4	2,346.5	2,908.9
Purchased Electricity for Resale	3,427.1	2,965.3	2,821.4
Other Operation	2,979.2	2,525.2	2,996.1
Maintenance	1,247.4	1,145.6	1,241.7
Asset Impairments and Other Related Charges	70.6	87.1	2,267.8
Gain on Sale of Merchant Generation Assets	—	(226.4)	—
Depreciation and Amortization	2,286.6	1,997.2	1,962.3
Taxes Other Than Income Taxes	1,142.7	1,059.4	1,018.0
TOTAL EXPENSES	13,513.0	11,899.9	15,216.2
OPERATING INCOME	2,682.7	3,525.0	1,163.9
Other Income (Expense):			
Interest and Investment Income	11.6	16.0	16.3
Carrying Costs Income	6.6	18.6	16.2
Allowance for Equity Funds Used During Construction	132.5	93.7	113.2
Non-Service Cost Components of Net Periodic Benefit Cost	124.5	45.5	43.2
Gain on Sale of Equity Investment	—	12.4	—
Interest Expense	(984.4)	(895.0)	(877.2)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	1,973.5	2,816.2	475.6
Income Tax Expense (Benefit)	115.3	969.7	(73.7)
Equity Earnings of Unconsolidated Subsidiaries	73.1	82.4	71.2
INCOME FROM CONTINUING OPERATIONS	1,931.3	1,928.9	620.5
LOSS FROM DISCONTINUED OPERATIONS, NET OF TAX	—	—	(2.5)
NET INCOME	1,931.3	1,928.9	618.0
Net Income Attributable to Noncontrolling Interests	7.5	16.3	7.1
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,923.8	$ 1,912.6	$ 610.9
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	492,774,600	491,814,651	491,495,458
BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM CONTINUING OPERATIONS	$ 3.90	$ 3.89	$ 1.25
BASIC EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM DISCONTINUED OPERATIONS	—	—	(0.01)
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3.90	$ 3.89	$ 1.24
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	493,758,277	492,611,067	491,662,007
DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM CONTINUING OPERATIONS	$ 3.90	$ 3.88	$ 1.25

DILUTED EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS FROM DISCONTINUED OPERATIONS	—	—	(0.01)
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3.90	$ 3.88	$ 1.24

See Notes to Financial Statements of Registrants beginning on page 175.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31,		
	2018	**2017**	**2016**
Net Income	$ 1,931.3	$ 1,928.9	$ 618.0
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $3.9, $(1.4) and $(8.8) in 2018, 2017 and 2016, Respectively	14.6	(2.6)	(16.4)
Securities Available for Sale, Net of Tax of $0, $1.9 and $0.7 in 2018, 2017 and 2016, Respectively	—	3.5	1.3
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(1.4), $0.6 and $0.3 in 2018, 2017 and 2016, Respectively	(5.3)	1.1	0.6
Pension and OPEB Funded Status, Net of Tax of $(8.8), $46.7 and $(7.9) in 2018, 2017 and 2016, Respectively	(33.0)	86.5	(14.7)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(23.7)	88.5	(29.2)
TOTAL COMPREHENSIVE INCOME	1,907.6	2,017.4	588.8
Total Comprehensive Income Attributable to Noncontrolling Interests	7.5	16.3	7.1
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,900.1	$ 2,001.1	$ 581.7

See Notes to Financial Statements of Registrants beginning on page 175.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2015	511.4	$ 3,324.0	$ 6,296.5	$ 8,398.3	$ (127.1)	$ 13.2	$ 17,904.9
Issuance of Common Stock	0.6	4.3	29.9				34.2
Common Stock Dividends				(1,116.8) (a)		(4.2)	(1,121.0)
Other Changes in Equity			6.2			7.0	13.2
Net Income				610.9		7.1	618.0
Other Comprehensive Loss					(29.2)		(29.2)
TOTAL EQUITY – DECEMBER 31, 2016	512.0	3,328.3	6,332.6	7,892.4	(156.3)	23.1	17,420.1
Issuance of Common Stock	0.2	1.1	11.1				12.2
Common Stock Dividends				(1,178.3) (a)		(13.6)	(1,191.9)
Other Changes in Equity			55.0			0.8	55.8
Net Income				1,912.6		16.3	1,928.9
Other Comprehensive Income					88.5		88.5
TOTAL EQUITY – DECEMBER 31, 2017	512.2	3,329.4	6,398.7	8,626.7	(67.8)	26.6	18,313.6
Issuance of Common Stock	1.3	8.0	65.6				73.6
Common Stock Dividends				(1,251.1) (a)		(4.4)	(1,255.5)
Other Changes in Equity			21.8			1.3	23.1
ASU 2018-02 Adoption				14.0	(17.0)		(3.0)
ASU 2016-01 Adoption				11.9	(11.9)		—
Net Income				1,923.8		7.5	1,931.3
Other Comprehensive Loss					(23.7)		(23.7)
TOTAL EQUITY – DECEMBER 31, 2018	513.5	$ 3,337.4	$ 6,486.1	$ 9,325.3	$ (120.4)	$ 31.0	$ 19,059.4

(a) Cash dividends declared per AEP common share were $2.53, $2.39 and $2.27 for the years ended December 31, 2018, 2017 and 2016, respectively.

See Notes to Financial Statements of Registrants beginning on page 175.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2018 and 2017
(in millions)

	December 31, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$ 234.1	$ 214.6
Restricted Cash (December 31, 2018 and 2017 Amounts Include $210 and $198, Respectively, Related to Transition Funding, Ohio Phase-in-Recovery Funding and Appalachian Consumer Rate Relief Funding)	210.0	198.0
Other Temporary Investments (December 31, 2018 and 2017 Amounts Include $152.7 and $155.4, Respectively, Related to EIS and Transource Energy)	159.1	161.7
Accounts Receivable:		
Customers	699.0	643.9
Accrued Unbilled Revenues	209.3	230.2
Pledged Accounts Receivable – AEP Credit	999.8	954.2
Miscellaneous	55.2	101.2
Allowance for Uncollectible Accounts	(36.8)	(38.5)
Total Accounts Receivable	1,926.5	1,891.0
Fuel	341.5	387.7
Materials and Supplies	579.6	565.5
Risk Management Assets	162.8	126.2
Regulatory Asset for Under-Recovered Fuel Costs	150.1	292.5
Margin Deposits	141.4	105.5
Prepayments and Other Current Assets	208.8	310.4
TOTAL CURRENT ASSETS	4,113.9	4,253.1
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	21,699.9	20,760.5
Transmission	21,531.0	18,972.5
Distribution	21,195.4	19,868.5
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	4,265.0	3,706.3
Construction Work in Progress	4,393.9	4,120.7
Total Property, Plant and Equipment	73,085.2	67,428.5
Accumulated Depreciation and Amortization	17,986.1	17,167.0
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	55,099.1	50,261.5
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,310.4	3,587.6
Securitized Assets	920.6	1,211.2
Spent Nuclear Fuel and Decommissioning Trusts	2,474.9	2,527.6
Goodwill	52.5	52.5
Long-term Risk Management Assets	254.0	282.1
Deferred Charges and Other Noncurrent Assets	2,577.4	2,553.5
TOTAL OTHER NONCURRENT ASSETS	9,589.8	10,214.5
TOTAL ASSETS	$ 68,802.8	$ 64,729.1

See Notes to Financial Statements of Registrants beginning on page 175.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2018 and 2017
(dollars in millions)

	December 31, 2018	December 31, 2017
CURRENT LIABILITIES		
Accounts Payable	$ 1,874.3	$ 2,065.3
Short-term Debt:		
Securitized Debt for Receivables – AEP Credit	750.0	718.0
Other Short-term Debt	1,160.0	920.6
Total Short-term Debt	1,910.0	1,638.6
Long-term Debt Due Within One Year (December 31, 2018 and 2017 Amounts Include $406.5 and $406.9, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and Sabine)	1,698.5	1,753.7
Risk Management Liabilities	55.0	61.6
Customer Deposits	412.2	357.0
Accrued Taxes	1,218.0	1,115.5
Accrued Interest	231.7	234.5
Regulatory Liability for Over-Recovered Fuel Costs	58.6	11.9
Other Current Liabilities	1,190.5	1,033.2
TOTAL CURRENT LIABILITIES	8,648.8	8,271.3
NONCURRENT LIABILITIES		
Long-term Debt (December 31, 2018 and 2017 Amounts Include $1,109.2 and $1,410.5, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, Transource Energy and Sabine)	21,648.2	19,419.6
Long-term Risk Management Liabilities	263.4	322.0
Deferred Income Taxes	7,086.5	6,813.9
Regulatory Liabilities and Deferred Investment Tax Credits	8,540.3	8,422.3
Asset Retirement Obligations	2,287.7	1,925.5
Employee Benefits and Pension Obligations	377.1	398.1
Deferred Credits and Other Noncurrent Liabilities	782.6	830.9
TOTAL NONCURRENT LIABILITIES	40,985.8	38,132.3
TOTAL LIABILITIES	49,634.6	46,403.6
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
MEZZANINE EQUITY		
Redeemable Noncontrolling Interest	69.4	—
Contingently Redeemable Performance Share Awards	39.4	11.9
TOTAL MEZZANINE EQUITY	108.8	11.9
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2018	2017
Shares Authorized	600,000,000	600,000,000
Shares Issued	513,450,036	512,210,644

	2018	2017
(20,204,160 and 20,205,046 Shares were Held in Treasury as of December 31, 2018 and 2017, Respectively)	3,337.4	3,329.4
Paid-in Capital	6,486.1	6,398.7
Retained Earnings	9,325.3	8,626.7
Accumulated Other Comprehensive Income (Loss)	(120.4)	(67.8)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	19,028.4	18,287.0
Noncontrolling Interests	31.0	26.6

TOTAL EQUITY	19,059.4	18,313.6
TOTAL LIABILITIES, MEZZANINE EQUITY AND TOTAL EQUITY	$ 68,802.8	$ 64,729.1

See Notes to Financial Statements of Registrants beginning on page 175.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31,		
	2018	2017	2016
OPERATING ACTIVITIES			
Net Income	$ 1,931.3	$ 1,928.9	$ 618.0
Loss from Discontinued Operations, Net of Tax	—	—	(2.5)
Income from Continuing Operations	1,931.3	1,928.9	620.5
Adjustments to Reconcile Income from Continuing Operations to Net Cash Flows from Continuing Operating Activities:			
Depreciation and Amortization	2,286.6	1,997.2	1,962.3
Deferred Income Taxes	104.3	901.5	(50.0)
Asset Impairments and Other Related Charges	70.6	87.1	2,267.8
Allowance for Equity Funds Used During Construction	(132.5)	(93.7)	(113.2)
Mark-to-Market of Risk Management Contracts	(66.4)	(23.3)	150.8
Amortization of Nuclear Fuel	113.8	129.1	128.6
Pension and Postemployment Benefit Reserves	(42.8)	27.8	21.6
Pension Contributions to Qualified Plan Trust	—	(93.3)	(84.8)
Property Taxes	(59.1)	(29.5)	(19.0)
Deferred Fuel Over/Under-Recovery, Net	189.7	84.4	(65.5)
Gain on Sale of Merchant Generation Assets	—	(226.4)	—
Recovery of Ohio Capacity Costs, Net	67.7	83.2	88.1
Provision for Refund – Global Settlement, Net	(5.5)	(98.2)	120.3
Disposition of Tanners Creek Plant Site	—	—	(93.5)
Change in Other Noncurrent Assets	119.8	(423.9)	(454.6)
Change in Other Noncurrent Liabilities	129.0	181.7	15.4
Changes in Certain Components of Continuing Working Capital:			
Accounts Receivable, Net	145.9	28.5	(226.6)
Fuel, Materials and Supplies	20.7	17.9	60.2
Accounts Payable	36.6	(58.0)	164.9
Accrued Taxes, Net	153.2	91.9	42.8
Other Current Assets	10.5	(60.7)	14.2
Other Current Liabilities	149.8	(181.8)	(28.5)
Net Cash Flows from Continuing Operating Activities	5,223.2	4,270.4	4,521.8
INVESTING ACTIVITIES			
Construction Expenditures	(6,310.9)	(5,691.3)	(4,781.1)
Purchases of Investment Securities	(2,067.8)	(2,314.7)	(3,002.3)
Sales of Investment Securities	2,010.0	2,256.3	2,957.7
Acquisitions of Nuclear Fuel	(46.1)	(108.0)	(128.5)
Acquisitions of Assets/Businesses	(14.6)	(6.8)	(107.9)
Proceeds from Sale of Merchant Generation Assets	—	2,159.6	—
Other Investing Activities	75.8	48.5	15.5
Net Cash Flows Used for Continuing Investing Activities	(6,353.6)	(3,656.4)	(5,046.6)
FINANCING ACTIVITIES			
Issuance of Common Stock	73.6	12.2	34.2
Issuance of Long-term Debt	4,945.7	3,854.1	2,594.9
Commercial Paper and Credit Facility Borrowings	205.6	—	—
Change in Short-term Debt, Net	271.4	(74.4)	913.0
Retirement of Long-term Debt	(2,782.0)	(3,087.9)	(1,794.9)
Commercial Paper and Credit Facility Repayments	(205.6)	—	—
Make Whole Premium on Extinguishment of Long-term Debt	(13.5)	(46.1)	—
Principal Payments for Capital Lease Obligations	(65.1)	(67.3)	(106.6)
Dividends Paid on Common Stock	(1,255.5)	(1,191.9)	(1,121.0)
Other Financing Activities	(12.7)	(3.6)	(15.7)
Net Cash Flows from (Used for) Continuing Financing Activities	1,161.9	(604.9)	503.9

Net Cash Flows Used for Discontinued Operating Activities	—	—	(2.5)
Net Cash Flows from Discontinued Investing Activities	—	—	—
Net Cash Flows from Discontinued Financing Activities	—	—	—
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	31.5	9.1	(23.4)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	412.6	403.5	426.9
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 444.1	$ 412.6	$ 403.5

See Notes to Financial Statements of Registrants beginning on page 175.

AEP TEXAS INC. AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

COMPANY OVERVIEW

AEP Texas was formed by the merger of TCC and TNC into AEP Utilities, Inc. on December 31, 2016. The merging parties retained their respective rate structures. Following the merger, AEP Utilities, Inc. changed its name to AEP Texas Inc.

Prior to the merger, AEP Utilities, Inc. was a subsidiary of AEP and holding company for TCC, TNC and CSW Energy, Inc. CSW Energy, Inc. owns Desert Sky and Trent. As a result of this merger, the assets and liabilities of CSW Energy, Inc. were transferred to a competitive AEP affiliate.

AEP Texas is engaged in the transmission and distribution of electric power to approximately 1,050,000 retail customers through REPs in west, central and southern Texas. Among the principal industries served by AEP Texas are petroleum and coal products manufacturing, chemical manufacturing, oil and gas extraction, pipeline transportation and primary metal manufacturing. The territory served by AEP Texas also includes several military installations and correctional facilities. AEP Texas is a member of ERCOT. Under Texas Restructuring Legislation, AEP Texas' utility predecessors, TCC and TNC, exited the generation business and ceased serving retail load. However, AEP Texas continues as part owner in the Oklaunion Power Station operated by PSO, which management announced plans to close by October 2020 pending necessary approvals. AEP Texas consolidates AEP Texas North Generation Company, LLC, AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III LLC, its wholly-owned subsidiaries.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2018	**2017**	**2016**
	(in millions of KWhs)		
Retail:			
Residential	12,101	11,569	11,844
Commercial	10,822	11,003	11,214
Industrial	8,531	8,418	7,892
Miscellaneous	566	563	577
Total Retail	32,020	31,553	31,527

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2018	**2017**	**2016**
	(in degree days)		
Actual – Heating (a)	354	239	201
Normal – Heating (b)	325	330	328
Actual – Cooling (c)	2,861	2,950	3,058
Normal – Cooling (b)	2,688	2,669	2,648

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Cooling degree days are calculated on a 70 degree temperature base.

2018 Compared to 2017

Reconciliation of Year Ended December 31, 2017 to Year Ended December 31, 2018
Net Income
(in millions)

Year Ended December 31, 2017	$	310.5
Changes in Gross Margin:		
Retail Margins		9.8
Off-system Sales		22.4
Transmission Revenues		8.3
Other Revenues		(1.2)
Total Change in Gross Margin		39.3
Changes in Expenses and Other:		
Other Operation and Maintenance		(49.3)
Depreciation and Amortization		(49.5)
Taxes Other Than Income Taxes		(10.3)
Interest Income		(2.1)
Allowance for Equity Funds Used During Construction		13.2
Non-Service Cost Components of Net Periodic Benefit Cost		8.7
Interest Expense		(5.0)
Total Change in Expenses and Other		(94.3)
Income Tax Expense (Benefit)		(44.2)
Year Ended December 31, 2018	$	211.3

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals were as follows:

- **Retail Margins** increased $10 million primarily due to the following:
  - A $12 million increase in revenues associated with the Distribution Cost Recovery Factor revenue rider.
  - A $10 million increase in revenues associated with the Transmission Cost Recovery Factor revenue rider. This increase was offset by an increase in Other Operation and Maintenance expenses below.
  - An $8 million increase in weather-related usage primarily driven by a 48% increase in heating degree days partially offset by a 3% decrease in cooling degree days.

  These increases were partially offset by:
  - An $18 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense (Benefit) below.
- **Margins from Off-system Sales** increased $22 million due to higher affiliated PPA revenues, which were offset by corresponding increases in Other Operation and Maintenance expenses and Depreciation and Amortization expenses below.
- **Transmission Revenues** increased $8 million primarily due to the following:
  - A $30 million increase due to recovery of increased transmission investment in ERCOT.

  This increase was partially offset by:
  - An $11 million decrease due to the 2018 provisions for customer refunds due to Tax Reform. This decrease was offset in Income Tax Expense (Benefit) below.
  - An $11 million decrease due to lower rates in order to pass the benefits of Tax Reform on to customers. This decrease was offset in Income Tax Expense (Benefit) below.

Expenses and Other and Income Tax Expense (Benefit) changed between years as follows:

- **Other Operation and Maintenance** expenses increased $49 million primarily due to the following:
  - A $25 million increase in ERCOT transmission expenses. This increase was partially offset by an increase in Retail Margins above.
  - A $7 million increase in distribution expenses.
  - A $5 million increase in affiliated PPA expenses. This increase was offset by an increase in Margins from Off-system sales above.
  - A $4 million increase primarily due to employee-related expenses.
- **Depreciation and Amortization** expenses increased $50 million primarily due to the following:
  - A $20 million increase in depreciation expense primarily due to an increase in the depreciable base of transmission and distribution assets.
  - A $14 million increase in depreciation expense due to a revision in the life expectancy of the Oklaunion Power Station. This increase was offset by an increase in Margins from Off-system sales above.
  - A $9 million increase in securitization amortizations related to Transition Funding. This increase was offset in Other Revenues above and Interest Expense below.
- **Taxes Other Than Income Taxes** increased $10 million primarily due to increased property taxes as a result of additional capital investment and increased tax rates.
- **Allowance for Equity Funds Used During Construction** increased $13 million primarily due to increased transmission projects.
- **Non-Service Cost Components of Net Periodic Cost** decreased $9 million primarily due to favorable asset returns for the funded Pension and OPEB plans, favorable OPEB cost savings arrangements and the implementation of ASU 2017-07.
- **Interest Expense** increased $5 million primarily due to the following:
  - A $25 million increase due to the issuances of long-term debt.

  This increase was partially offset by:
  - A $12 million decrease due to a higher debt component of AFUDC and increased investment primarily in transmission projects.
  - An $11 million decrease in expense related to Transition Funding securitization assets. This decrease was offset above in Other Revenues and Depreciation and Amortization.
- **Income Tax Expense (Benefit)** increased $44 million primarily due to the income tax benefit recognized in 2017 related to the remeasurement of deferred tax liabilities from 35% to 21% as a result of Tax Reform partially offset by the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
AEP Texas Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of AEP Texas Inc. and its subsidiaries (the “Company”) as of December 31, 2018 and 2017, and the related consolidated statements of income, comprehensive income (loss), changes in common shareholder’s equity, and cash flows for each of the two years in the period ended December 31, 2018, including the related notes (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 21, 2019

We have served as the Company's auditor since 2017.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
AEP Texas Inc.

We have audited the accompanying consolidated statements of income, comprehensive income (loss), changes in common shareholder's equity, and cash flows of AEP Texas Inc. and subsidiaries (the "Company") for the year ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the results of operations and cash flows of AEP Texas Inc. and subsidiaries for the year ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Columbus, Ohio
April 26, 2017 (November 16, 2017 as to Note 9)

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of AEP Texas Inc. and Subsidiaries (AEP Texas) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEP Texas' internal control is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of AEP Texas' internal control over financial reporting as of December 31, 2018. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded AEP Texas' internal control over financial reporting was effective as of December 31, 2018.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, AEP Texas' registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit AEP Texas to provide only management's report in this annual report.

AEP TEXAS INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31,		
	2018	**2017**	**2016**
REVENUES			
Electric Transmission and Distribution	$ 1,486.3	$ 1,470.3	$ 1,383.2
Sales to AEP Affiliates	105.2	65.7	75.7
Other Revenues	3.8	2.4	2.5
TOTAL REVENUES	1,595.3	1,538.4	1,461.4
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	38.5	20.9	32.1
Other Operation	488.9	453.1	457.8
Maintenance	89.4	75.9	73.7
Depreciation and Amortization	499.6	450.1	413.9
Taxes Other Than Income Taxes	132.6	122.3	107.6
TOTAL EXPENSES	1,249.0	1,122.3	1,085.1
OPERATING INCOME	346.3	416.1	376.3
Other Income (Expense):			
Interest Income	0.8	2.9	10.9
Allowance for Equity Funds Used During Construction	20.0	6.8	9.2
Non-Service Cost Components of Net Periodic Benefit Cost	12.3	3.6	3.3
Interest Expense	(147.3)	(142.3)	(144.4)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE (BENEFIT)	232.1	287.1	255.3
Income Tax Expense (Benefit)	20.8	(23.4)	59.9
INCOME FROM CONTINUING OPERATIONS	211.3	310.5	195.4
LOSS FROM DISCONTINUED OPERATIONS, NET OF TAX	—	—	(48.8)
NET INCOME	$ 211.3	$ 310.5	$ 146.6

The common stock of AEP Texas is wholly-owned by Parent.

See Notes to Financial Statements of Registrants beginning on page 175.

AEP TEXAS INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31,		
	2018	**2017**	**2016**
Net Income	$ 211.3	$ 310.5	$ 146.6
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $0.3, $0.5 and $0.6 in 2018, 2017 and 2016, Respectively	1.0	0.9	1.1
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0.1, $0.1 and $0.2 in 2018, 2017 and 2016, Respectively	0.2	0.3	0.3
Pension and OPEB Funded Status, Net of Tax of $(0.3), $0.6 and $0.5 in 2018, 2017 and 2016, Respectively	(1.0)	1.1	0.9
TOTAL OTHER COMPREHENSIVE INCOME	0.2	2.3	2.3
TOTAL COMPREHENSIVE INCOME	$ 211.5	$ 312.8	$ 148.9

See Notes to Financial Statements of Registrants beginning on page 175.

AEP TEXAS INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2015	$ 804.9	$ 887.0	$ (17.2)	$ 1,674.7
Capital Contribution from Parent	53.0			53.0
Common Stock Dividends		(34.0)		(34.0)
Net Income		146.6		146.6
Other Comprehensive Income			2.3	2.3
Distribution of CSW Energy, Inc. to Parent		(185.5)		(185.5)
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2016	857.9	814.1	(14.9)	1,657.1
Capital Contribution from Parent	200.0			200.0
Net Income		310.5		310.5
Other Comprehensive Income			2.3	2.3
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2017	1,057.9	1,124.6	(12.6)	2,169.9
Capital Contribution from Parent	200.0			200.0
ASU 2018-02 Adoption		1.8	(2.7)	(0.9)
Net Income		211.3		211.3
Other Comprehensive Income			0.2	0.2
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2018	$ 1,257.9	$ 1,337.7	$ (15.1)	$ 2,580.5

See Notes to Financial Statements of Registrants beginning on page 175.

AEP TEXAS INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2018 and 2017
(in millions)

	December 31,	
	2018	**2017**
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3.1	$ 2.0
Restricted Cash for Securitized Transition Funding	156.7	155.2
Advances to Affiliates	8.0	111.9
Accounts Receivable:		
Customers	110.9	105.3
Affiliated Companies	15.0	12.3
Accrued Unbilled Revenues	70.4	75.8
Miscellaneous	1.9	1.3
Allowance for Uncollectible Accounts	(1.3)	(0.7)
Total Accounts Receivable	196.9	194.0
Fuel	8.8	3.6
Materials and Supplies	52.8	52.0
Risk Management Assets	—	0.5
Accrued Tax Benefits	44.9	41.0
Prepayments and Other Current Assets	5.3	3.6
TOTAL CURRENT ASSETS	476.5	563.8
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	352.1	350.7
Transmission	3,683.6	3,053.6
Distribution	4,043.2	3,718.6
Other Property, Plant and Equipment	727.9	461.0
Construction Work in Progress	836.2	835.7
Total Property, Plant and Equipment	9,643.0	8,419.6
Accumulated Depreciation and Amortization	1,651.2	1,594.5
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	7,991.8	6,825.1
OTHER NONCURRENT ASSETS		
Regulatory Assets	430.0	378.7
Securitized Transition Assets (December 31, 2018 and 2017 Amounts Include $636.8 and $869.5, Respectively, Related to Transition Funding)	649.1	891.2
Deferred Charges and Other Noncurrent Assets	56.3	114.8
TOTAL OTHER NONCURRENT ASSETS	1,135.4	1,384.7
TOTAL ASSETS	$ 9,603.7	$ 8,773.6

See Notes to Financial Statements of Registrants beginning on page 175.

AEP TEXAS INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2018 and 2017
(in millions)

	December 31, 2018	December 31, 2017
CURRENT LIABILITIES		
Advances from Affiliates	$ 216.0	$ —
Accounts Payable:		
General	276.5	379.4
Affiliated Companies	30.3	30.2
Long-term Debt Due Within One Year – Nonaffiliated (December 31, 2018 and 2017 Amounts Include $251.1 and $236.1, Respectively, Related to Transition Funding)	501.1	266.1
Risk Management Liabilities	0.2	—
Accrued Taxes	75.5	77.2
Accrued Interest (December 31, 2018 and 2017 Amounts Include $11.3 and $15.9, Respectively, Related to Transition Funding)	37.3	42.2
Oklaunion Purchase Power Agreement	24.3	—
Other Current Liabilities	98.3	76.4
TOTAL CURRENT LIABILITIES	1,259.5	871.5
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (December 31, 2018 and 2017 Amounts Include $540.1 and $790.1, Respectively, Related to Transition Funding)	3,380.2	3,383.2
Deferred Income Taxes	913.1	913.1
Regulatory Liabilities and Deferred Investment Tax Credits	1,344.3	1,320.5
Oklaunion Purchase Power Agreement	22.1	52.0
Deferred Credits and Other Noncurrent Liabilities	104.0	63.4
TOTAL NONCURRENT LIABILITIES	5,763.7	5,732.2
TOTAL LIABILITIES	7,023.2	6,603.7
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Paid-in Capital	1,257.9	1,057.9
Retained Earnings	1,337.7	1,124.6
Accumulated Other Comprehensive Income (Loss)	(15.1)	(12.6)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,580.5	2,169.9
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 9,603.7	$ 8,773.6

See Notes to Financial Statements of Registrants beginning on page 175.

AEP TEXAS INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31, 2018	2017	2016
OPERATING ACTIVITIES			
Net Income	$ 211.3	$ 310.5	$ 146.6
Loss from Discontinued Operations	—	—	(48.8)
Income from Continuing Operations	211.3	310.5	195.4
Adjustments to Reconcile Income from Continuing Operations to Net Cash Flows from Continuing Operating Activities:			
Depreciation and Amortization	499.6	450.1	413.9
Deferred Income Taxes	(16.5)	63.3	29.5
Allowance for Equity Funds Used During Construction	(20.0)	(6.8)	(9.2)
Mark-to-Market of Risk Management Contracts	0.7	(0.3)	(0.5)
Pension Contributions to Qualified Plan Trust	—	(8.8)	(8.2)
Change in Regulatory Asset – Catastrophe Reserve	(24.9)	(99.2)	(0.9)
Change in Other Noncurrent Assets	(35.4)	(49.4)	(44.1)
Change in Other Noncurrent Liabilities	44.9	8.8	(10.3)
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(2.9)	(23.5)	(22.6)
Fuel, Materials and Supplies	(6.0)	3.2	5.9
Accounts Payable	(20.3)	30.8	(3.0)
Accrued Taxes, Net	(5.6)	(31.3)	(22.6)
Other Current Assets	0.8	0.6	(0.2)
Other Current Liabilities	26.2	(15.3)	(6.5)
Net Cash Flows from Continuing Operating Activities	651.9	632.7	516.6
INVESTING ACTIVITIES			
Construction Expenditures	(1,428.8)	(990.9)	(640.9)
Change in Advances to Affiliates, Net	103.9	(103.3)	139.0
Other Investing Activities	35.2	18.9	10.4
Net Cash Flows Used for Continuing Investing Activities	(1,289.7)	(1,075.3)	(491.5)
FINANCING ACTIVITIES			
Capital Contribution from Parent	200.0	200.0	53.0
Issuance of Long-term Debt – Nonaffiliated	494.0	749.6	199.2
Change in Advances from Affiliates, Net	216.0	(169.5)	117.0
Retirement of Long-term Debt – Nonaffiliated	(266.1)	(323.1)	(428.7)
Principal Payments for Capital Lease Obligations	(4.7)	(3.9)	(3.4)
Dividends Paid on Common Stock	—	—	(34.0)
Other Financing Activities	1.2	(0.2)	0.8
Net Cash Flows from (Used for) Continuing Financing Activities	640.4	452.9	(96.1)
Net Cash Flows from Discontinued Operating Activities	—	—	42.4
Net Cash Flows from Discontinued Investing Activities	—	—	11.7
Net Cash Flows Used for Discontinued Financing Activities	—	—	(44.6)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash for Securitized Transition Funding	2.6	10.3	(61.5)
Cash, Cash Equivalents and Restricted Cash for Securitized Transition Funding at Beginning of Period	157.2	146.9	208.4
Cash, Cash Equivalents and Restricted Cash for Securitized Transition Funding at End of Period	$ 159.8	$ 157.2	$ 146.9
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 145.9	$ 134.6	$ 145.6
Net Cash Paid (Received) for Income Taxes	7.9	(28.3)	38.2
Noncash Acquisitions Under Capital Leases	10.6	8.2	7.1
Construction Expenditures Included in Current Liabilities as of December 31,	243.1	325.7	100.1

Noncash Distribution of CSW Energy, Inc. to Parent	—	—	185.5

See Notes to Financial Statements of Registrants beginning on page 175.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

COMPANY OVERVIEW

AEPTCo is a holding company for seven FERC regulated transmission-only electric utilities. AEPTCo is an indirect wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP").

AEPTCo's seven wholly-owned public utility companies are (collectively referred to herein as the "State Transcos"):

- AEP Appalachian Transmission Company, Inc. ("APTCo")
- AEP Indiana Michigan Transmission Company, Inc. ("IMTCo")
- AEP Kentucky Transmission Company, Inc. ("KTCo")
- AEP Ohio Transmission Company, Inc. ("OHTCo")
- AEP West Virginia Transmission Company, Inc. ("WVTCo")
- AEP Oklahoma Transmission Company, Inc. ("OKTCo")
- AEP Southwestern Transmission Company, Inc. ("SWTCo")

AEPTCo's business activities are the development, construction and operation of transmission facilities through investments in seven wholly-owned FERC-regulated transmission only electric subsidiaries.

RESULTS OF OPERATIONS

Summary of Investment in Transmission Assets for AEPTCo

	As of December 31,		
	2018	**2017**	**2016**
		(in millions)	
Plant In Service	$ 6,689.8	$ 5,446.5	$ 4,072.9
CWIP	1,578.3	1,324.0	981.3
Accumulated Depreciation	271.9	152.6	99.6
Total Transmission Property, Net	$ 7,996.2	$ 6,617.9	$ 4,954.6

2018 Compared to 2017

Reconciliation of Year Ended December 31, 2017 to Year Ended December 31, 2018
Net Income
(in millions)

Year Ended December 31, 2017	$ 270.7
Changes in Transmission Revenues:	
Transmission Revenues	69.2
Total Change in Transmission Revenues	69.2
Changes in Expenses and Other:	
Other Operation and Maintenance	(25.7)
Depreciation and Amortization	(38.2)
Taxes Other Than Income Taxes	(28.1)
Interest Income	1.3
Allowance for Equity Funds Used During Construction	21.6
Interest Expense	(13.0)
Total Change in Expenses and Other	(82.1)
Income Tax Expense	58.1
Year Ended December 31, 2018	$ 315.9

The amounts presented in the tables above reflect the revisions made to AEPTCo's previously issued financial statements. See the "Revisions to Previously Issued Financial Statements" section of Note 1 for additional information.

The major components of the increase in transmission revenues, which consists of wholesale sales to affiliates and nonaffiliates were as follows:

- **Transmission Revenues** increased $69 million primarily due to:
  - A $133 million increase in revenues driven by an increase in the formula rate revenue requirement primarily driven by continued investment in transmission assets. This increase includes the impact of the reduction in revenue related to Tax Reform, which was offset by a decrease in Income Tax Expense below.

  This increase was partially offset by:
  - A $64 million decrease in revenues due to a lower annual formula rate true-up in 2018 driven by implementing forward looking formula rates in 2017.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses increased $26 million primarily due to increased transmission investment.
- **Depreciation and Amortization** expenses increased $38 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $28 million primarily due to higher property taxes as a result of increased transmission investment.
- **Allowance for Equity Funds Used During Construction** increased $22 million primarily due to increased transmission investment resulting in a higher CWIP balance.
- **Interest Expense** increased $13 million primarily due to the following:
  - A $21 million increase primarily due to higher long-term debt balances.

  This increase was partially offset by:
  - A $7 million decrease due to higher AFUDC borrowed funds resulting from a higher CWIP balance.
- **Income Tax Expense** decreased $58 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Member of
AEP Transmission Company, LLC

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of AEP Transmission Company, LLC and its subsidiaries (the "Company") as of December 31, 2018 and 2017, and the related consolidated statements of income, changes in member's equity, and cash flows for each of the two years in the period ended December 31, 2018, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 21, 2019

We have served as the Company's auditor since 2017.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Managers and Shareholder of
AEP Transmission Company, LLC

We have audited the accompanying consolidated statements of income, changes in member's equity, and cash flows of AEP Transmission Company, LLC and subsidiaries (the "Company") for the year ended December 31, 2016. Our audit also included the 2016 financial statement schedule listed in Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the results of operations and cash flows of AEP Transmission Company, LLC and subsidiaries for the year ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such 2016 financial statement schedule, when considered in relation to the 2016 basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ Deloitte & Touche LLP

Columbus, Ohio
April 4, 2017

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of AEP Transmission Company, LLC and Subsidiaries (AEPTCo) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEPTCo's internal control is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of AEPTCo's internal control over financial reporting as of December 31, 2018. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded AEPTCo's internal control over financial reporting was effective as of December 31, 2018.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, AEPTCo's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit AEPTCo to provide only management's report in this annual report.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31,		
	2018	2017	2016
REVENUES			
Transmission Revenues	$ 177.0	$ 138.0	$ 110.4
Sales to AEP Affiliates	598.9	568.1	367.5
Other Revenues	0.2	0.8	0.1
TOTAL REVENUES	776.1	706.9	478.0
EXPENSES			
Other Operation	83.8	60.1	37.0
Maintenance	10.5	8.5	6.7
Depreciation and Amortization	133.9	95.7	65.9
Taxes Other Than Income Taxes	137.8	109.7	88.3
TOTAL EXPENSES	366.0	274.0	197.9
OPERATING INCOME	410.1	432.9	280.1
Other Income (Expense):			
Interest Income	2.5	1.2	0.4
Allowance for Equity Funds Used During Construction	70.6	49.0	52.3
Interest Expense	(83.2)	(70.2)	(46.0)
INCOME BEFORE INCOME TAX EXPENSE	400.0	412.9	286.8
Income Tax Expense	84.1	142.2	94.1
NET INCOME	$ 315.9	$ 270.7	$ 192.7

The 2017 amounts presented reflect the revisions made to AEPTCo's previously issued financial statements.

See Notes to Financial Statements of Registrants beginning on page 175.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Paid-in Capital	Retained Earnings	Total Member's Equity
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2015	$ 1,243.0	$ 309.9	$ 1,552.9
Capital Contributions from Member	212.0		212.0
Net Income		192.7	192.7
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2016	1,455.0	502.6	1,957.6
Capital Contributions from Member	361.6		361.6
Net Income		270.7	270.7
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2017	1,816.6	773.3	2,589.9
Capital Contributions from Member	664.0		664.0
Net Income		315.9	315.9
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2018	$ 2,480.6	$ 1,089.2	$ 3,569.8

The 2017 amounts presented reflect the revisions made to AEPTCo's previously issued financial statements.

See Notes to Financial Statements of Registrants beginning on page 175.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2018 and 2017
(in millions)

	December 31, 2018	December 31, 2017
CURRENT ASSETS		
Advances to Affiliates	$ 96.9	$ 146.3
Accounts Receivable:		
Customers	11.8	15.0
Affiliated Companies	61.0	93.2
Miscellaneous	—	1.3
Total Accounts Receivable	72.8	109.5
Materials and Supplies	19.0	13.6
Accrued Tax Benefits	33.4	49.4
Prepayments and Other Current Assets	3.4	7.6
TOTAL CURRENT ASSETS	225.5	326.4
TRANSMISSION PROPERTY		
Transmission Property	6,515.8	5,319.7
Other Property, Plant and Equipment	174.0	126.8
Construction Work in Progress	1,578.3	1,324.0
Total Transmission Property	8,268.1	6,770.5
Accumulated Depreciation and Amortization	271.9	152.6
TOTAL TRANSMISSION PROPERTY – NET	7,996.2	6,617.9
OTHER NONCURRENT ASSETS		
Regulatory Assets	12.9	11.7
Deferred Property Taxes	157.9	125.0
Deferred Charges and Other Noncurrent Assets	1.6	1.1
TOTAL OTHER NONCURRENT ASSETS	172.4	137.8
TOTAL ASSETS	$ 8,394.1	$ 7,082.1

The 2017 amounts presented reflect the revisions made to AEPTCo's previously issued financial statements.

See Notes to Financial Statements of Registrants beginning on page 175.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND MEMBER'S EQUITY
December 31, 2018 and 2017

	December 31, 2018	December 31, 2017
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 45.4	$ 15.7
Accounts Payable:		
General	347.2	484.5
Affiliated Companies	56.0	66.1
Long-term Debt Due Within One Year – Nonaffiliated	85.0	50.0
Accrued Taxes	288.9	231.5
Accrued Interest	15.9	15.0
Other Current Liabilities	3.8	4.1
TOTAL CURRENT LIABILITIES	842.2	866.9
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,738.0	2,500.4
Deferred Income Taxes	704.4	600.4
Regulatory Liabilities	521.3	493.8
Deferred Credits and Other Noncurrent Liabilities	18.4	30.7
TOTAL NONCURRENT LIABILITIES	3,982.1	3,625.3
TOTAL LIABILITIES	4,824.3	4,492.2
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
MEMBER'S EQUITY		
Paid-in Capital	2,480.6	1,816.6
Retained Earnings	1,089.2	773.3
TOTAL MEMBER'S EQUITY	3,569.8	2,589.9
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 8,394.1	$ 7,082.1

The 2017 amounts presented reflect the revisions made to AEPTCo's previously issued financial statements.

See Notes to Financial Statements of Registrants beginning on page 175.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31, 2018	2017	2016
OPERATING ACTIVITIES			
Net Income	$ 315.9	$ 270.7	$ 192.7
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	133.9	95.7	65.9
Deferred Income Taxes	98.9	271.5	223.1
Allowance for Equity Funds Used During Construction	(70.6)	(49.0)	(52.3)
Property Taxes	(32.9)	(22.8)	(15.3)
Change in Other Noncurrent Assets	14.6	11.0	(2.8)
Change in Other Noncurrent Liabilities	17.4	27.5	4.4
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	36.7	(30.4)	(22.6)
Materials and Supplies	(5.4)	(8.6)	(5.0)
Accounts Payable	(7.5)	23.0	14.3
Accrued Taxes, Net	73.4	16.3	143.8
Accrued Interest	0.9	4.5	2.6
Other Current Assets	(0.3)	(4.8)	0.1
Other Current Liabilities	(26.4)	0.2	—
Net Cash Flows from Operating Activities	548.6	604.8	548.9
INVESTING ACTIVITIES			
Construction Expenditures	(1,526.4)	(1,513.4)	(1,159.5)
Change in Advances to Affiliates, Net	49.4	(79.2)	29.0
Acquisitions of Assets	(37.4)	(9.1)	(6.5)
Other Investing Activities	1.1	6.1	2.0
Net Cash Flows Used for Investing Activities	(1,513.3)	(1,595.6)	(1,135.0)
FINANCING ACTIVITIES			
Capital Contributions from Member	664.0	361.6	212.0
Issuance of Long-term Debt – Nonaffiliated	321.0	617.6	686.9
Change in Advances from Affiliates, Net	29.7	11.6	(12.8)
Retirement of Long-term Debt – Nonaffiliated	(50.0)	—	(300.0)
Net Cash Flows from Financing Activities	964.7	990.8	586.1
Net Change in Cash and Cash Equivalents	—	—	—
Cash and Cash Equivalents at Beginning of Period	—	—	—
Cash and Cash Equivalents at End of Period	$ —	$ —	$ —
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 80.2	$ 62.4	$ 42.0
Net Cash Paid (Received) for Income Taxes	(30.7)	(107.3)	(235.1)
Noncash Acquisitions Under Capital Leases	—	0.2	—
Construction Expenditures Included in Current Liabilities as of December 31,	345.0	485.0	298.3

The 2017 amounts presented reflect the revisions made to AEPTCo's previously issued financial statements.

See Notes to Financial Statements of Registrants beginning on page 175.

**APPALACHIAN POWER COMPANY
AND SUBSIDIARIES**

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

COMPANY OVERVIEW

As a public utility, APCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 956,000 retail customers in its service territory in southwestern Virginia and southern West Virginia. APCo consolidates Cedar Coal Company, Central Appalachian Coal Company, Southern Appalachian Coal Company and Appalachian Consumer Rate Relief Funding LLC, its wholly-owned subsidiaries. APCo sells power at wholesale to municipalities. APCo shares its off-system sales margins with its Virginia customers. APCo's off-system sales margins are returned to APCo's West Virginia customers through the ENEC clause.

Under the FERC approved PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. The PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

The FERC also approved a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent. The Bridge Agreement is an interim arrangement that amongst other things addresses the treatment of purchases and sales made by AEPSC on behalf of the member companies that extend beyond termination of the Interconnection Agreement.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo and WPCo. Power and natural gas risk management activities are allocated based on the member companies' respective equity positions. Risk management activities primarily include power and natural gas physical transactions, financially-settled swaps and exchange-traded futures. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts. APCo shared in the revenues and expenses associated with these risk management activities with the member companies.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM generally accruing to the benefit of APCo, I&M, KPCo and WPCo and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the common shareholder's equity of these companies.

To minimize the credit requirements and operating constraints when operating within PJM, participating AEP companies, including APCo, agreed to a netting of certain payment obligations incurred by the participating AEP companies against certain balances due to such AEP companies and to hold PJM harmless from actions that any one or more AEP companies may take with respect to PJM.

APCo is jointly and severally liable for activity conducted by AEPSC on behalf of APCo, I&M, KPCo and WPCo related to power purchase and sale activity.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2018	**2017**	**2016**
	(in millions of KWhs)		
Retail:			
Residential	11,870	10,701	11,421
Commercial	6,603	6,453	6,750
Industrial	9,555	9,603	9,410
Miscellaneous	866	836	857
Total Retail	28,894	27,593	28,438
Wholesale	2,693	3,089	3,400
Total KWhs	31,587	30,682	31,838

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2018	**2017**	**2016**
	(in degree days)		
Actual – Heating (a)	2,400	1,848	2,105
Normal – Heating (b)	2,230	2,235	2,257
Actual – Cooling (c)	1,587	1,249	1,480
Normal – Cooling (b)	1,208	1,201	1,198

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Cooling degree days are calculated on a 65 degree temperature base.

2018 Compared to 2017

Reconciliation of Year Ended December 31, 2017 to Year Ended December 31, 2018
Net Income
(in millions)

Year Ended December 31, 2017	$ 331.3
Changes in Gross Margin:	
Retail Margins	(105.8)
Off-system Sales	2.6
Transmission Revenues	3.8
Other Revenues	(4.8)
Total Change in Gross Margin	(104.2)
Changes in Expenses and Other:	
Other Operation and Maintenance	(73.8)
Depreciation and Amortization	(20.5)
Taxes Other Than Income Taxes	(8.3)
Interest Income	0.4
Carrying Costs Income	(0.1)
Allowance for Equity Funds Used During Construction	4.0
Non-Service Cost Components of Net Periodic Benefit Cost	12.7
Interest Expense	(3.9)
Total Change in Expenses and Other	(89.5)
Income Tax Expense (Benefit)	230.2
Year Ended December 31, 2018	$ 367.8

The major components of the decrease in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** decreased $106 million primarily due to the following:
  - A $78 million reduction of deferred fuel under-recovery related to the West Virginia Tax Reform settlement. This decrease was offset in Income Tax Expense (Benefit) below.
  - A $74 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was partially offset in Other Operation and Maintenance expenses and Income Tax Expense (Benefit) below.
  - A $25 million increase in net ENEC recoverable PJM expenses that were offset below.
  - A $20 million decrease in weather-normalized margins occurring across all retail classes.
  - A $10 million increase in non-recoverable fuel expense related to Virginia legislation.

  These decreases were partially offset by:
  - A $97 million increase in weather-related usage primarily driven by a 29% increase in heating degree days along with a 27% increase in cooling degree days.
  - A $5 million increase primarily due to increases from rate riders in Virginia. This increase was partially offset by an increase in Other Operation and Maintenance expenses.
- **Transmission Revenues** increased $4 million primarily due to the annual formula rate true-up and decreased PJM provisions.
- **Other Revenues** decreased $5 million primarily due to a decrease in services provided to third-parties.

Expenses and Other and Income Tax Expense (Benefit) changed between years as follows:

- **Other Operation and Maintenance** expenses increased $74 million primarily due to the following:
  - A $39 million increase in expenses due to the extinguishment of regulatory asset balances as agreed to within the West Virginia Tax Reform settlement. This increase was partially offset in Retail Margins above and Income Tax Expense (Benefit) below.
  - A $28 million increase in storm-related expenses primarily in Virginia.
  - A $19 million increase in recoverable PJM transmission expenses. This increase was primarily offset within Retail Margins above.
  - A $9 million increase in employee-related expenses.
  - A $5 million increase in estimated expenses for claims related to asbestos exposure.

  These increases were partially offset by:
  - A $43 million decrease in PJM expenses primarily related to the annual formula rate true-up that will be refunded in future periods.
- **Depreciation and Amortization** expenses increased $21 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $8 million primarily due to an increase in property taxes due to additional investments in utility plant.
- **Allowance for Equity Funds Used During Construction** increased $4 million due to an increase in construction activity.
- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $13 million primarily due to favorable asset returns for the funded Pension and OPEB plans, favorable OPEB cost savings arrangements and the implementation of ASU 2017-07.
- **Interest Expense** increased $4 million primarily due to higher long-term debt balances.
- **Income Tax Expense (Benefit)** decreased $230 million primarily due to the impact of the West Virginia Tax Reform settlement, the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Appalachian Power Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Appalachian Power Company and its subsidiaries (the "Company") as of December 31, 2018 and 2017, and the related consolidated statements of income, comprehensive income (loss), changes in common shareholder's equity, and cash flows for each of the two years in the period ended December 31, 2018, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 21, 2019

We have served as the Company's auditor since 2017.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Appalachian Power Company:

We have audited the accompanying consolidated statements of income, comprehensive income (loss), changes in common shareholder's equity, and cash flows of Appalachian Power Company and subsidiaries (the "Company") for the year ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the results of operations and cash flows of Appalachian Power Company and subsidiaries for the year ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2017

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Appalachian Power Company and Subsidiaries (APCo) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. APCo's internal control is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of APCo's internal control over financial reporting as of December 31, 2018. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded APCo's internal control over financial reporting was effective as of December 31, 2018.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, APCo's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit APCo to provide only management's report in this annual report.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31, 2018	2017	2016
REVENUES			
Electric Generation, Transmission and Distribution	$ 2,777.1	$ 2,749.0	$ 2,847.4
Sales to AEP Affiliates	181.4	172.0	142.1
Other Revenues	9.0	13.2	11.7
TOTAL REVENUES	2,967.5	2,934.2	3,001.2
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	588.9	597.3	654.9
Purchased Electricity for Resale	503.5	357.6	329.3
Other Operation	511.6	503.1	491.7
Maintenance	316.9	251.6	275.0
Depreciation and Amortization	428.4	407.9	388.5
Taxes Other Than Income Taxes	134.7	126.4	123.5
TOTAL EXPENSES	2,484.0	2,243.9	2,262.9
OPERATING INCOME	483.5	690.3	738.3
Other Income (Expense):			
Interest Income	1.8	1.4	1.3
Carrying Costs Income	1.3	1.4	0.4
Allowance for Equity Funds Used During Construction	13.2	9.2	11.7
Non-Service Cost Components of Net Periodic Benefit Cost	17.9	5.2	5.0
Interest Expense	(194.8)	(190.9)	(188.5)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	322.9	516.6	568.2
Income Tax Expense (Benefit)	(44.9)	185.3	199.1
NET INCOME	$ 367.8	$ 331.3	$ 369.1

The common stock of APCo is wholly-owned by Parent.

See Notes to Financial Statements of Registrants beginning on page 175.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31,		
	2018	**2017**	**2016**
Net Income	$ 367.8	$ 331.3	$ 369.1
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $(0.2), $(0.4) and $(0.4) in 2018, 2017 and 2016, Respectively	(0.9)	(0.7)	(0.7)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.8), $(0.6) and $(0.8) in 2018, 2017 and 2016, Respectively	(3.1)	(1.2)	(1.4)
Pension and OPEB Funded Status, Net of Tax of $(0.7), $6.3 and $(1.9) in 2018, 2017 and 2016, Respectively	(2.6)	11.6	(3.5)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(6.6)	9.7	(5.6)
TOTAL COMPREHENSIVE INCOME	$ 361.2	$ 341.0	$ 363.5

See Notes to Financial Statements of Registrants beginning on page 175.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2015	$ 260.4	$ 1,828.7	$ 1,388.7	$ (2.8)	$ 3,475.0
Common Stock Dividends			(255.0)		(255.0)
Net Income			369.1		369.1
Other Comprehensive Loss				(5.6)	(5.6)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	260.4	1,828.7	1,502.8	(8.4)	3,583.5
Common Stock Dividends			(120.0)		(120.0)
Net Income			331.3		331.3
Other Comprehensive Income				9.7	9.7
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	260.4	1,828.7	1,714.1	1.3	3,804.5
Common Stock Dividends			(160.0)		(160.0)
ASU 2018-02 Adoption			0.1	0.3	0.4
Net Income			367.8		367.8
Other Comprehensive Loss				(6.6)	(6.6)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	$ 260.4	$ 1,828.7	$ 1,922.0	$ (5.0)	$ 4,006.1

See Notes to Financial Statements of Registrants beginning on page 175.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2018 and 2017
(in millions)

	December 31, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$ 4.2	$ 2.9
Restricted Cash for Securitized Funding	25.6	16.3
Advances to Affiliates	23.0	23.5
Accounts Receivable:		
Customers	146.5	123.1
Affiliated Companies	73.4	69.3
Accrued Unbilled Revenues	63.5	74.1
Miscellaneous	2.3	1.1
Allowance for Uncollectible Accounts	(2.3)	(3.7)
Total Accounts Receivable	283.4	263.9
Fuel	61.3	89.3
Materials and Supplies	100.1	99.5
Risk Management Assets	57.2	24.9
Regulatory Asset for Under-Recovered Fuel Costs	99.6	88.8
Prepayments and Other Current Assets	44.3	27.1
TOTAL CURRENT ASSETS	698.7	636.2
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,509.6	6,446.9
Transmission	3,317.7	3,019.9
Distribution	3,989.4	3,763.8
Other Property, Plant and Equipment	485.8	427.9
Construction Work in Progress	490.2	483.0
Total Property, Plant and Equipment	14,792.7	14,141.5
Accumulated Depreciation and Amortization	4,124.4	3,896.4
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	10,668.3	10,245.1
OTHER NONCURRENT ASSETS		
Regulatory Assets	475.8	573.9
Securitized Assets	258.7	282.3
Long-term Risk Management Assets	0.9	1.1
Deferred Charges and Other Noncurrent Assets	188.1	190.0
TOTAL OTHER NONCURRENT ASSETS	923.5	1,047.3
TOTAL ASSETS	$ 12,290.5	$ 11,928.6

See Notes to Financial Statements of Registrants beginning on page 175.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2018 and 2017

	December 31, 2018	December 31, 2017
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 205.6	$ 186.0
Accounts Payable:		
General	263.8	264.9
Affiliated Companies	84.0	92.7
Long-term Debt Due Within One Year – Nonaffiliated	430.7	249.2
Risk Management Liabilities	0.4	1.3
Customer Deposits	88.4	86.1
Accrued Taxes	89.3	94.5
Other Current Liabilities	191.8	149.5
TOTAL CURRENT LIABILITIES	1,354.0	1,124.2
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,631.9	3,730.9
Long-term Risk Management Liabilities	0.2	0.2
Deferred Income Taxes	1,625.8	1,565.7
Regulatory Liabilities and Deferred Investment Tax Credits	1,449.7	1,454.9
Asset Retirement Obligations	107.1	100.2
Employee Benefits and Pension Obligations	57.1	73.3
Deferred Credits and Other Noncurrent Liabilities	58.6	74.7
TOTAL NONCURRENT LIABILITIES	6,930.4	6,999.9
TOTAL LIABILITIES	8,284.4	8,124.1
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260.4	260.4
Paid-in Capital	1,828.7	1,828.7
Retained Earnings	1,922.0	1,714.1
Accumulated Other Comprehensive Income (Loss)	(5.0)	1.3
TOTAL COMMON SHAREHOLDER'S EQUITY	4,006.1	3,804.5
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 12,290.5	$ 11,928.6

See Notes to Financial Statements of Registrants beginning on page 175.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31,		
	2018	2017	2016
OPERATING ACTIVITIES			
Net Income	$ 367.8	$ 331.3	$ 369.1
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	428.4	407.9	388.5
Deferred Income Taxes	(16.8)	171.5	130.7
Carrying Costs Income	(1.3)	(1.4)	(0.4)
Allowance for Equity Funds Used During Construction	(13.2)	(9.2)	(11.7)
Mark-to-Market of Risk Management Contracts	(33.0)	(23.1)	9.4
Pension Contributions to Qualified Plan Trust	—	(10.2)	(8.8)
Deferred Fuel Over/Under-Recovery, Net	(10.8)	(20.5)	22.2
Change in Other Noncurrent Assets	59.4	12.8	3.4
Change in Other Noncurrent Liabilities	(4.8)	11.9	(26.1)
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	33.6	(28.0)	(48.0)
Fuel, Materials and Supplies	27.8	22.3	12.9
Accounts Payable	(13.3)	37.5	19.5
Accrued Taxes, Net	(13.2)	(12.7)	53.7
Other Current Assets	(6.1)	0.7	(9.8)
Other Current Liabilities	42.1	(10.8)	(9.9)
Net Cash Flows from Operating Activities	846.6	880.0	894.7
INVESTING ACTIVITIES			
Construction Expenditures	(780.7)	(818.1)	(646.7)
Change in Advances to Affiliates, Net	0.5	0.6	1.5
Other Investing Activities	10.8	15.2	13.3
Net Cash Flows Used for Investing Activities	(769.4)	(802.3)	(631.9)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	203.2	320.9	314.0
Change in Advances from Affiliates, Net	19.6	106.4	(101.4)
Retirement of Long-term Debt – Nonaffiliated	(124.0)	(377.9)	(213.6)
Principal Payments for Capital Lease Obligations	(6.9)	(6.9)	(6.4)
Dividends Paid on Common Stock	(160.0)	(120.0)	(255.0)
Other Financing Activities	1.5	0.5	0.5
Net Cash Flows Used for Financing Activities	(66.6)	(77.0)	(261.9)
Net Increase in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	10.6	0.7	0.9
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	19.2	18.5	17.6
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$ 29.8	$ 19.2	$ 18.5
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 182.0	$ 183.6	$ 181.8
Net Cash Paid (Received) for Income Taxes	(13.0)	31.2	22.1
Noncash Acquisitions Under Capital Leases	5.5	3.5	6.1
Construction Expenditures Included in Current Liabilities as of December 31,	134.4	126.3	151.6

See Notes to Financial Statements of Registrants beginning on page 175.

**INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES**

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

COMPANY OVERVIEW

As a public utility, I&M engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 596,000 retail customers in its service territory in northern and eastern Indiana and southwestern Michigan. I&M consolidates Blackhawk Coal Company and Price River Coal Company, its wholly-owned subsidiaries. I&M also consolidates DCC Fuel. I&M sells power at wholesale to municipalities and electric cooperatives. I&M's River Transportation Division provides barging services to affiliates and nonaffiliated companies. The revenues from barging represent the majority of other revenues. I&M shares off-system sales margins with its customers.

Under the FERC approved PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. The PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

The FERC also approved a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent. The Bridge Agreement is an interim arrangement that amongst other things addresses the treatment of purchases and sales made by AEPSC on behalf of the member companies that extend beyond termination of the Interconnection Agreement.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo and WPCo. Power and natural gas risk management activities are allocated based on the member companies' respective equity positions. Risk management activities primarily include power and natural gas physical transactions, financially-settled swaps and exchange-traded futures. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts. I&M shared in the revenues and expenses associated with these risk management activities with the member companies.

AEGCo holds a 50% interest in each of the Rockport Plant units and is entitled to 50% of the capacity and associated energy from each unit. Under unit power agreements approved by the FERC, I&M and KPCo purchase approximately 920 MWs and 390 MWs, respectively, of the output from AEGCo's 50% share of the Rockport Plant.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM generally accruing to the benefit of APCo, I&M, KPCo and WPCo and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the common shareholder's equity of these companies.

To minimize the credit requirements and operating constraints when operating within PJM, participating AEP companies, including I&M, agreed to a netting of certain payment obligations incurred by the participating AEP companies against certain balances due to such AEP companies and to hold PJM harmless from actions that any one or more AEP companies may take with respect to PJM.

I&M is jointly and severally liable for activity conducted by AEPSC on behalf of APCo, I&M, KPCo and WPCo related to power purchase and sale activity.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2018	**2017**	**2016**
	(in millions of KWhs)		
Retail:			
Residential	5,731	5,311	5,578
Commercial	4,905	4,826	4,979
Industrial	7,782	7,740	7,780
Miscellaneous	71	70	71
Total Retail	18,489	17,947	18,408
Wholesale	10,873	11,202	8,994
Total KWhs	29,362	29,149	27,402

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2018	**2017**	**2016**
	(in degree days)		
Actual – Heating (a)	3,886	3,213	3,429
Normal – Heating (b)	3,747	3,758	3,779
Actual – Cooling (c)	1,132	792	1,039
Normal – Cooling (b)	849	846	845

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Cooling degree days are calculated on a 65 degree temperature base.

2018 Compared to 2017

Reconciliation of Year Ended December 31, 2017 to Year Ended December 31, 2018
Net Income
(in millions)

Year Ended December 31, 2017	$	186.7
Changes in Gross Margin:		
Retail Margins		127.1
Off-system Sales		(10.4)
Transmission Revenues		24.0
Other Revenues		2.0
Total Change in Gross Margin		142.7
Changes in Expenses and Other:		
Other Operation and Maintenance		(23.8)
Depreciation and Amortization		(82.2)
Taxes Other Than Income Taxes		(6.7)
Interest Income		1.6
Carrying Costs Income		(8.8)
Allowance for Equity Funds Used During Construction		0.8
Non-Service Cost Components of Net Periodic Benefit Cost		12.0
Interest Expense		(13.3)
Total Change in Expenses and Other		(120.4)
Income Tax Expense		52.3
Year Ended December 31, 2018	$	261.3

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** increased $127 million primarily due to the following:
  - A $71 million increase from base rate proceedings in the I&M service territory, inclusive of a $47 million decrease due to the impact of Tax Reform in the Indiana jurisdiction. The increase in Retail Margins relating to riders had corresponding increases in other expense items below.
  - A $53 million increase in weather-related usage primarily due to a 21% increase in heating degree days and a 43% increase in cooling degree days.
  - A $33 million increase in FERC generation wholesale municipal and cooperative revenues primarily due to the annual formula rate true-up and changes to the formula rate.

  These increases were partially offset by:
  - A $19 million decrease due to customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
  - A $14 million decrease due to lower weather-normalized margins primarily due to wholesale customer load loss from contracts that expired at the end of 2017.
  - A $6 million decrease due to increased costs for power acquired under the UPA between AEGCo and I&M.
- **Margins from Off-system Sales** decreased $10 million primarily due to mid-year changes in the OSS sharing mechanism.
- **Transmission Revenues** increased $24 million primarily due to the annual formula rate true-up and decreased PJM provisions.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses increased $24 million primarily due to the following:
  - A $14 million increase in distribution costs primarily due to vegetation management expenses.
  - A $13 million increase in generation expenses at Cook Plant primarily due to an increase in various maintenance activities.
  - An $8 million increase in employee-related expenses.
  - A $7 million increase in boiler maintenance expenses at Rockport Plant.
  - A $4 million increase in other expenses primarily due to a reduction in an environmental liability accrual in 2017.
  - A $3 million increase in demand-side management expenses. This increase was offset within Retail Margins above.

  These increases were partially offset by:
  - A $21 million decrease in transmission expenses primarily due to the annual formula rate true-up.
  - A $7 million decrease due to an increased Nuclear Electric Insurance Limited distribution in 2018.
- **Depreciation and Amortization** expenses increased $82 million primarily due to a higher depreciable base and increased depreciation rates approved in the 2017 Indiana and Michigan base rate cases.
- **Taxes Other Than Income Taxes** increased $7 million primarily due to increased state taxes due to higher reported taxable KWh and taxable revenues and a prior period refund.
- **Carrying Cost Income** decreased $9 million primarily due to a decrease in carrying charges for certain riders in the Indiana jurisdiction.
- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $12 million primarily due to favorable asset returns for the funded Pension and OPEB plans, favorable OPEB cost savings arrangements and the implementation of ASU 2017-07.
- **Interest Expense** increased $13 million primarily due to higher long-term debt balances.
- **Income Tax Expense** decreased $52 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform and amortization of Excess ADIT, partially offset by an increase in pretax book income.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Indiana Michigan Power Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Indiana Michigan Power Company and its subsidiaries (the "Company") as of December 31, 2018 and 2017, and the related consolidated statements of income, comprehensive income (loss), changes in common shareholder's equity, and cash flows for each of the two years in the period ended December 31, 2018, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 21, 2019

We have served as the Company's auditor since 2017.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Indiana Michigan Power Company:

We have audited the accompanying consolidated statements of income, comprehensive income (loss), changes in common shareholder's equity, and cash flows of Indiana Michigan Power Company and subsidiaries (the "Company") for the year ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the results of operations and cash flows of Indiana Michigan Power Company and subsidiaries for the year ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2017

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Indiana Michigan Power Company and Subsidiaries (I&M) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. I&M's internal control is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of I&M's internal control over financial reporting as of December 31, 2018. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded I&M's internal control over financial reporting was effective as of December 31, 2018.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, I&M's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit I&M to provide only management's report in this annual report.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31,		
	2018	**2017**	**2016**
REVENUES			
Electric Generation, Transmission and Distribution	$ 2,272.6	$ 2,042.5	$ 2,062.3
Sales to AEP Affiliates	22.1	1.8	26.2
Other Revenues – Affiliated	63.4	62.6	62.1
Other Revenues – Nonaffiliated	12.6	14.3	17.0
TOTAL REVENUES	2,370.7	2,121.2	2,167.6
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	318.3	295.1	284.1
Purchased Electricity for Resale	221.8	152.2	198.7
Purchased Electricity from AEP Affiliates	237.9	223.9	228.6
Other Operation	585.4	591.3	579.3
Maintenance	238.1	208.4	205.6
Asset Impairments and Other Related Charges	—	—	10.5
Depreciation and Amortization	293.1	210.9	191.7
Taxes Other Than Income Taxes	98.9	92.2	94.8
TOTAL EXPENSES	1,993.5	1,774.0	1,793.3
OPERATING INCOME	377.2	347.2	374.3
Other Income (Expense):			
Interest Income	3.4	1.8	1.2
Carrying Costs Income	3.9	12.7	10.1
Allowance for Equity Funds Used During Construction	11.9	11.1	15.3
Non-Service Cost Components of Net Periodic Benefit Cost	18.1	6.1	7.3
Interest Expense	(124.1)	(110.8)	(100.8)
INCOME BEFORE INCOME TAX EXPENSE	290.4	268.1	307.4
Income Tax Expense	29.1	81.4	67.5
NET INCOME	$ 261.3	$ 186.7	$ 239.9

The common stock of I&M is wholly-owned by Parent.

See Notes to Financial Statements of Registrants beginning on page 175.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31,		
	2018	2017	2016
Net Income	$ 261.3	$ 186.7	$ 239.9
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $0.4, $0.7 and $0.7 in 2018, 2017 and 2016, Respectively	1.6	1.3	1.3
Pension and OPEB Funded Status, Net of Tax of $(0.2), $1.5 and $(0.4) in 2018, 2017 and 2016, Respectively	(0.6)	2.8	(0.8)
TOTAL OTHER COMPREHENSIVE INCOME	1.0	4.1	0.5
TOTAL COMPREHENSIVE INCOME	$ 262.3	$ 190.8	$ 240.4

See Notes to Financial Statements of Registrants beginning on page 175.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2015	$ 56.6	$ 980.9	$ 1,015.6	$ (16.7)	$ 2,036.4
Common Stock Dividends			(125.0)		(125.0)
Net Income			239.9		239.9
Other Comprehensive Income				0.5	0.5
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	56.6	980.9	1,130.5	(16.2)	2,151.8
Common Stock Dividends			(125.0)		(125.0)
Net Income			186.7		186.7
Other Comprehensive Income				4.1	4.1
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	56.6	980.9	1,192.2	(12.1)	2,217.6
Common Stock Dividends			(124.7)		(124.7)
ASU 2018-02 Adoption			0.3	(2.7)	(2.4)
Net Income			261.3		261.3
Other Comprehensive Income				1.0	1.0
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	$ 56.6	$ 980.9	$ 1,329.1	$ (13.8)	$ 2,352.8

See Notes to Financial Statements of Registrants beginning on page 175.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2018 and 2017
(in millions)

	December 31, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2.4	$ 1.3
Advances to Affiliates	12.7	12.4
Accounts Receivable:		
Customers	63.1	56.4
Affiliated Companies	75.0	50.0
Accrued Unbilled Revenues	3.6	7.3
Miscellaneous	1.4	2.0
Allowance for Uncollectible Accounts	(0.1)	(0.1)
Total Accounts Receivable	143.0	115.6
Fuel	37.3	31.4
Materials and Supplies	167.3	160.6
Risk Management Assets	8.6	7.6
Accrued Tax Benefits	26.6	58.4
Regulatory Asset for Under-Recovered Fuel Costs	—	15.0
Accrued Reimbursement of Spent Nuclear Fuel Costs	7.9	10.8
Prepayments and Other Current Assets	24.6	20.9
TOTAL CURRENT ASSETS	430.4	434.0
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,887.2	4,445.9
Transmission	1,576.8	1,504.0
Distribution	2,249.7	2,069.3
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	583.8	595.2
Construction Work in Progress	465.3	460.2
Total Property, Plant and Equipment	9,762.8	9,074.6
Accumulated Depreciation, Depletion and Amortization	3,151.6	3,024.2
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,611.2	6,050.4
OTHER NONCURRENT ASSETS		
Regulatory Assets	512.5	579.4
Spent Nuclear Fuel and Decommissioning Trusts	2,474.9	2,527.6
Long-term Risk Management Assets	0.6	0.7
Deferred Charges and Other Noncurrent Assets	193.0	179.9
TOTAL OTHER NONCURRENT ASSETS	3,181.0	3,287.6
TOTAL ASSETS	$ 10,222.6	$ 9,772.0

See Notes to Financial Statements of Registrants beginning on page 175.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2018 and 2017
(dollars in millions)

	December 31, 2018	December 31, 2017
CURRENT LIABILITIES		
Advances from Affiliates	$ 1.1	$ 211.6
Accounts Payable:		
General	174.7	154.5
Affiliated Companies	70.2	98.3
Long-term Debt Due Within One Year – Nonaffiliated (December 31, 2018 and 2017 Amounts Include $76.8 and $96.3, Respectively, Related to DCC Fuel)	155.4	474.7
Risk Management Liabilities	0.3	3.5
Customer Deposits	38.0	37.7
Accrued Taxes	90.7	81.3
Accrued Interest	37.3	37.5
Regulatory Liability for Over-Recovered Fuel Costs	27.4	2.7
Other Current Liabilities	103.0	109.5
TOTAL CURRENT LIABILITIES	698.1	1,211.3
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,880.0	2,270.4
Long-term Risk Management Liabilities	0.1	0.1
Deferred Income Taxes	948.0	953.8
Regulatory Liabilities and Deferred Investment Tax Credits	1,574.5	1,708.7
Asset Retirement Obligations	1,681.3	1,321.6
Deferred Credits and Other Noncurrent Liabilities	87.8	88.5
TOTAL NONCURRENT LIABILITIES	7,171.7	6,343.1
TOTAL LIABILITIES	7,869.8	7,554.4
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 2,500,000 Shares		
Outstanding – 1,400,000 Shares	56.6	56.6
Paid-in Capital	980.9	980.9
Retained Earnings	1,329.1	1,192.2
Accumulated Other Comprehensive Income (Loss)	(13.8)	(12.1)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,352.8	2,217.6
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 10,222.6	$ 9,772.0

See Notes to Financial Statements of Registrants beginning on page 175.

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31, 2018	2017	2016
OPERATING ACTIVITIES			
Net Income	$ 261.3	$ 186.7	$ 239.9
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	293.1	210.9	191.7
Deferred Income Taxes	(42.9)	200.7	105.1
Amortization (Deferral) of Incremental Nuclear Refueling Outage Expenses, Net	29.2	8.5	(48.4)
Asset Impairments and Other Related Charges	—	—	10.5
Carrying Costs Income	(3.9)	(12.7)	(10.1)
Allowance for Equity Funds Used During Construction	(11.9)	(11.1)	(15.3)
Mark-to-Market of Risk Management Contracts	(4.1)	(2.3)	2.0
Amortization of Nuclear Fuel	113.8	129.1	128.6
Pension Contributions to Qualified Plan Trust	—	(13.0)	(12.7)
Deferred Fuel Over/Under-Recovery, Net	39.7	13.7	(14.8)
Disposition of Tanners Creek Plant Site	—	—	(93.5)
Change in Other Noncurrent Assets	(32.6)	(88.4)	(56.4)
Change in Other Noncurrent Liabilities	72.1	37.4	58.2
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	4.8	(1.1)	0.5
Fuel, Materials and Supplies	(11.2)	(7.5)	20.9
Accounts Payable	(14.1)	17.6	11.6
Accrued Taxes, Net	41.2	(16.6)	6.0
Other Current Assets	1.5	14.5	8.0
Other Current Liabilities	(10.3)	(5.1)	(2.1)
Net Cash Flows from Operating Activities	725.7	661.3	529.7
INVESTING ACTIVITIES			
Construction Expenditures	(568.5)	(648.5)	(596.9)
Change in Advances to Affiliates, Net	(0.3)	0.1	(0.8)
Purchases of Investment Securities	(2,064.7)	(2,300.5)	(3,000.0)
Sales of Investment Securities	2,010.0	2,256.3	2,957.7
Acquisitions of Nuclear Fuel	(46.1)	(108.0)	(128.5)
Other Investing Activities	14.8	9.7	8.4
Net Cash Flows Used for Investing Activities	(654.8)	(790.9)	(760.1)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	1,168.1	530.1	569.4
Change in Advances from Affiliates, Net	(210.5)	(3.6)	(79.1)
Retirement of Long-term Debt – Nonaffiliated	(884.9)	(260.7)	(100.2)
Principal Payments for Capital Lease Obligations	(8.8)	(12.0)	(35.3)
Dividends Paid on Common Stock	(124.7)	(125.0)	(125.0)
Other Financing Activities	(9.0)	0.9	0.7
Net Cash Flows from (Used for) Financing Activities	(69.8)	129.7	230.5
Net Increase in Cash and Cash Equivalents	1.1	0.1	0.1
Cash and Cash Equivalents at Beginning of Period	1.3	1.2	1.1
Cash and Cash Equivalents at End of Period	$ 2.4	$ 1.3	$ 1.2
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 116.9	$ 94.8	$ 83.3
Net Cash Paid (Received) for Income Taxes	32.6	(89.9)	(39.5)
Noncash Acquisitions Under Capital Leases	5.8	7.1	18.2
Construction Expenditures Included in Current Liabilities as of December 31,	93.0	88.5	106.2

Acquisition of Nuclear Fuel Included in Current Liabilities as of December 31,	4.0	—	2.1
Expected Reimbursement for Capital Cost of Spent Nuclear Fuel Dry Cask Storage	2.2	2.6	0.7

See Notes to Financial Statements of Registrants beginning on page 175.

OHIO POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

COMPANY OVERVIEW

As a public utility, OPCo engages in the transmission and distribution of power to 1,486,000 retail customers in the northwestern, central, eastern and southern sections of Ohio. OPCo purchases energy and capacity at auction to serve its remaining SSO customers. In accordance with the PUCO's corporate separation order, OPCo remains responsible to provide power and capacity to OPCo customers who have not switched electric providers. Effective January 2014, OPCo purchased power from both affiliated and nonaffiliated entities, subject to auction requirements and PUCO approval, to meet the energy and capacity needs of customers. OPCo consolidates Ohio Phase-in-Recovery Funding LLC, its wholly-owned subsidiary.

The FERC approved a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent. The Bridge Agreement is an interim arrangement that amongst other things addresses the treatment of purchases and sales made by AEPSC on behalf of the member companies that extend beyond termination of the Interconnection Agreement.

AEPSC conducts gasoline, diesel fuel, energy procurement and risk management activities on OPCo's behalf.

To minimize the credit requirements and operating constraints when operating within PJM, participating AEP companies, including OPCo, agreed to a netting of certain payment obligations incurred by the participating AEP companies against certain balances due to such AEP companies and to hold PJM harmless from actions that any one or more AEP companies may take with respect to PJM.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2018	**2017**	**2016**
	(in millions of KWhs)		
Retail:			
Residential	14,940	13,539	14,314
Commercial	14,733	14,387	14,672
Industrial	14,779	14,664	14,279
Miscellaneous	115	119	123
Total Retail (a)	44,567	42,709	43,388
Wholesale (b)	2,441	2,387	1,888
Total KWhs	47,008	45,096	45,276

(a) Represents energy delivered to distribution customers.
(b) Primarily Ohio's contractually obligated purchases of OVEC power sold into PJM.

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2018	**2017**	**2016**
	(in degree days)		
Actual – Heating (a)	3,357	2,709	2,957
Normal – Heating (b)	3,215	3,225	3,245
Actual – Cooling (c)	1,402	1,002	1,248
Normal – Cooling (b)	980	974	969

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Cooling degree days are calculated on a 65 degree temperature base.

2018 Compared to 2017

Reconciliation of Year Ended December 31, 2017 to Year Ended December 31, 2018
Net Income
(in millions)

Year Ended December 31, 2017	$	323.9
Changes in Gross Margin:		
Retail Margins		145.0
Off-system Sales		40.9
Transmission Revenues		(9.9)
Other Revenues		3.3
Total Change in Gross Margin		179.3
Changes in Expenses and Other:		
Other Operation and Maintenance		(270.1)
Depreciation and Amortization		(33.8)
Taxes Other Than Income Taxes		(21.3)
Interest Income		(1.5)
Carrying Costs Income		(1.9)
Allowance for Equity Funds Used During Construction		3.4
Non-Service Cost Components of Net Periodic Benefit Cost		11.0
Interest Expense		1.2
Total Change in Expenses and Other		(313.0)
Income Tax Expense		135.3
Year Ended December 31, 2018	$	325.5

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of purchased electricity and amortization of generation deferrals were as follows:

- **Retail Margins** increased $145 million primarily due to the following:
  - A $173 million net increase in Basic Transmission Cost Rider revenues and recoverable PJM expenses. This increase was partially offset by an increase in Other Operation and Maintenance expenses below.
  - A $77 million increase in revenues associated with the Universal Service Fund (USF). This increase was offset by a corresponding increase in Other Operation and Maintenance expenses below.
  - A $16 million increase in rider revenues associated with the DIR. This increase was partially offset in various expenses below.
  - A $10 million increase in rider revenues recovering state excise taxes due to an increase in metered KWh. This increase was offset by a corresponding increase in Taxes Other Than Income Taxes below.
  - A $9 million increase in revenues associated with smart grid riders. This increase was partially offset by increases in various expenses below.
  - A $7 million increase in usage primarily in the residential class.

  These increases were partially offset by:
  - A $46 million decrease due to adjustments to the distribution decoupling under-recovery balance as a result of the 2018 Ohio Tax Reform settlement. This decrease was offset in Income Tax Expense below.
  - A $41 million decrease due to prior year over-recoveries and the recovery of lower current year losses from a power contract with OVEC. This decrease was offset by a corresponding increase in Margins from Off-system Sales below.
  - A $24 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
  - A $9 million net decrease in margin for the Phase-In-Recovery Rider including associated amortizations.
  - A $7 million decrease in rider revenues associated with the Tax Savings Credit Rider as a result of the 2018 Ohio Tax Reform Settlement. This decrease was offset in Income Tax Expense below.

- **Margins from Off-system Sales** increased $41 million due to prior year over-recoveries and lower current year losses from a power contract with OVEC which was offset in Retail Margins above as a result of the OVEC PPA rider beginning in January 2017.
- **Transmission Revenues** decreased $10 million primarily due to the 2018 provisions for customer refunds due to Tax Reform, partially offset by increased revenues due to additional transmission investments. This decrease was offset in Income Tax Expense below.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses increased $270 million primarily due to the following:
  - A $206 million increase in recoverable PJM expenses. This increase was offset within Gross Margins above.
  - A $77 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset by a corresponding increase in Retail Margins above.

  These increases were partially offset by:
  - A $58 million decrease in PJM expenses primarily related to the annual formula rate true-up that will be refunded in future periods.
- **Depreciation and Amortization** expenses increased $34 million primarily due to the following:
  - A $20 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
  - A $5 million increase in recoverable DIR depreciation expense. This increase was offset in Retail Margins above.
  - A $5 million increase in amortization due to capitalized software.
- **Taxes Other Than Income Taxes** increased $21 million primarily due to the following:
  - An $11 million increase in property taxes due to additional investments in transmission and distribution assets and higher tax rates.
  - A $9 million increase in rider revenues recovering state excise taxes due to an increase in metered KWhs. This increase was offset by a corresponding increase in Retail Margins above.
- **Non-Service Cost Components of Net Periodic Cost** decreased $11 million primarily due to favorable asset returns for the funded Pension and OPEB plans, favorable OPEB cost savings arrangements and the implementation of ASU 2017-07.
- **Income Tax Expense** decreased $135 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Ohio Power Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Ohio Power Company and its subsidiaries (the “Company”) as of December 31, 2018 and 2017, and the related consolidated statements of income, comprehensive income (loss), changes in common shareholder’s equity, and cash flows for each of the two years in the period ended December 31, 2018, including the related notes (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 21, 2019

We have served as the Company's auditor since 2017.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Ohio Power Company:

We have audited the accompanying consolidated statements of income, comprehensive income (loss), changes in common shareholder's equity, and cash flows of Ohio Power Company and subsidiaries (the "Company") for the year ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the results of operations and cash flows of Ohio Power Company and subsidiaries for the year ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2017

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Ohio Power Company and Subsidiaries (OPCo) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. OPCo's internal control is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of OPCo's internal control over financial reporting as of December 31, 2018. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded OPCo's internal control over financial reporting was effective as of December 31, 2018.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, OPCo's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit OPCo to provide only management's report in this annual report.

OHIO POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31, 2018	2017	2016
REVENUES			
Electricity, Transmission and Distribution	$ 3,033.8	$ 2,853.5	$ 2,930.1
Sales to AEP Affiliates	21.0	24.4	17.3
Other Revenues	8.6	6.0	6.5
TOTAL REVENUES	3,063.4	2,883.9	2,953.9
EXPENSES			
Purchased Electricity for Resale	684.6	705.9	663.1
Purchased Electricity from AEP Affiliates	135.3	108.5	141.9
Generation Deferrals	—	—	(82.7)
Amortization of Generation Deferrals	223.9	229.2	242.9
Other Operation	771.3	516.0	711.2
Maintenance	156.0	141.2	148.0
Depreciation and Amortization	259.7	225.9	238.6
Taxes Other Than Income Taxes	412.8	391.5	386.8
TOTAL EXPENSES	2,643.6	2,318.2	2,449.8
OPERATING INCOME	419.8	565.7	504.1
Other Income (Expense):			
Interest Income	3.4	4.9	3.8
Carrying Costs Income	1.7	3.6	19.9
Allowance for Equity Funds Used During Construction	9.8	6.4	6.0
Non-Service Cost Components of Net Periodic Benefit Cost	15.5	4.5	4.4
Interest Expense	(100.7)	(101.9)	(112.2)
INCOME BEFORE INCOME TAX EXPENSE	349.5	483.2	426.0
Income Tax Expense	24.0	159.3	143.8
NET INCOME	$ 325.5	$ 323.9	$ 282.2

The common stock of OPCo is wholly-owned by Parent.

See Notes to Financial Statements of Registrants beginning on page 175.

OHIO POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31,		
	2018	2017	2016
Net Income	$ 325.5	$ 323.9	$ 282.2
OTHER COMPREHENSIVE LOSS, NET OF TAXES			
Cash Flow Hedges, Net of Tax of $(0.4), $(0.6) and $(0.7) in 2018, 2017 and 2016, Respectively	(1.3)	(1.1)	(1.3)
TOTAL COMPREHENSIVE INCOME	$ 324.2	$ 322.8	$ 280.9

See Notes to Financial Statements of Registrants beginning on page 175.

OHIO POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2015	$ 321.2	$ 838.8	$ 822.3	$ 4.3	$ 1,986.6
Common Stock Dividends			(150.0)		(150.0)
Net Income			282.2		282.2
Other Comprehensive Loss				(1.3)	(1.3)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	321.2	838.8	954.5	3.0	2,117.5
Common Stock Dividends			(130.0)		(130.0)
Net Income			323.9		323.9
Other Comprehensive Loss				(1.1)	(1.1)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	321.2	838.8	1,148.4	1.9	2,310.3
Common Stock Dividends			(337.5)		(337.5)
ASU 2018-02 Adoption				0.4	0.4
Net Income			325.5		325.5
Other Comprehensive Loss				(1.3)	(1.3)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	$ 321.2	$ 838.8	$ 1,136.4	$ 1.0	$ 2,297.4

See Notes to Financial Statements of Registrants beginning on page 175.

OHIO POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2018 and 2017
(in millions)

	December 31, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$ 4.9	$ 3.1
Restricted Cash for Securitized Funding	27.6	26.6
Accounts Receivable:		
Customers	111.1	67.8
Affiliated Companies	70.8	70.2
Accrued Unbilled Revenues	21.4	29.7
Miscellaneous	0.3	1.9
Allowance for Uncollectible Accounts	(1.0)	(0.6)
Total Accounts Receivable	202.6	169.0
Materials and Supplies	42.9	41.9
Renewable Energy Credits	25.9	25.0
Risk Management Assets	—	0.6
Regulatory Asset for Under-Recovered Fuel Costs	0.4	115.9
Prepayments and Other Current Assets	15.3	15.8
TOTAL CURRENT ASSETS	319.6	397.9
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Transmission	2,544.3	2,419.2
Distribution	4,942.3	4,626.4
Other Property, Plant and Equipment	574.8	495.9
Construction Work in Progress	432.1	410.1
Total Property, Plant and Equipment	8,493.5	7,951.6
Accumulated Depreciation and Amortization	2,218.6	2,184.8
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,274.9	5,766.8
OTHER NONCURRENT ASSETS		
Regulatory Assets	387.5	652.8
Securitized Assets	12.9	37.7
Deferred Charges and Other Noncurrent Assets	441.0	406.5
TOTAL OTHER NONCURRENT ASSETS	841.4	1,097.0
TOTAL ASSETS	$ 7,435.9	$ 7,261.7

See Notes to Financial Statements of Registrants beginning on page 175.

OHIO POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2018 and 2017
(dollars in millions)

	December 31, 2018	December 31, 2017
CURRENT LIABILITIES		
Advances from Affiliates	$ 114.1	$ 87.8
Accounts Payable:		
General	211.9	205.8
Affiliated Companies	102.9	118.2
Long-term Debt Due Within One Year – Nonaffiliated (December 31, 2018 and 2017 Amounts Include $47.8 and $47, Respectively, Related to Ohio Phase-in-Recovery Funding)	47.9	397.0
Risk Management Liabilities	5.8	6.4
Customer Deposits	113.1	69.2
Accrued Taxes	537.8	512.5
Other Current Liabilities	214.2	196.9
TOTAL CURRENT LIABILITIES	1,347.7	1,593.8
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (December 31, 2018 and 2017 Amounts Include $0 and $47.5, Respectively, Related to Ohio Phase-in-Recovery Funding)	1,668.7	1,322.3
Long-term Risk Management Liabilities	93.8	126.0
Deferred Income Taxes	763.3	762.9
Regulatory Liabilities and Deferred Investment Tax Credits	1,221.2	1,100.2
Deferred Credits and Other Noncurrent Liabilities	43.8	46.2
TOTAL NONCURRENT LIABILITIES	3,790.8	3,357.6
TOTAL LIABILITIES	5,138.5	4,951.4
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value:		
Authorized – 40,000,000 Shares		
Outstanding – 27,952,473 Shares	321.2	321.2
Paid-in Capital	838.8	838.8
Retained Earnings	1,136.4	1,148.4
Accumulated Other Comprehensive Income (Loss)	1.0	1.9
TOTAL COMMON SHAREHOLDER'S EQUITY	2,297.4	2,310.3
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 7,435.9	$ 7,261.7

See Notes to Financial Statements of Registrants beginning on page 175.

OHIO POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31,		
	2018	2017	2016
OPERATING ACTIVITIES			
Net Income	$ 325.5	$ 323.9	$ 282.2
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	259.7	225.9	238.6
Generation Deferrals	—	—	(82.7)
Amortization of Generation Deferrals	223.9	229.2	242.9
Deferred Income Taxes	(36.2)	147.9	(39.2)
Carrying Costs Income	(1.7)	(3.6)	(19.9)
Allowance for Equity Funds Used During Construction	(9.8)	(6.4)	(6.0)
Mark-to-Market of Risk Management Contracts	(32.2)	13.0	134.6
Pension Contributions to Qualified Plan Trust	—	(8.2)	(7.1)
Property Taxes	(12.5)	(17.9)	(9.8)
Provision for Refund – Global Settlement	(5.5)	(98.2)	120.3
Change in Regulatory Assets	171.5	(70.7)	(139.8)
Change in Other Noncurrent Assets	(9.8)	(51.1)	(44.6)
Change in Other Noncurrent Liabilities	53.8	15.8	31.0
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	43.1	(30.1)	(26.6)
Materials and Supplies	(11.3)	(11.1)	(2.1)
Accounts Payable	(13.8)	11.6	13.7
Accrued Taxes, Net	26.8	(9.4)	(6.0)
Other Current Assets	8.1	(9.2)	—
Other Current Liabilities	49.1	(29.2)	(33.2)
Net Cash Flows from Operating Activities	1,028.7	622.2	646.3
INVESTING ACTIVITIES			
Construction Expenditures	(725.9)	(567.7)	(416.2)
Change in Advances to Affiliates, Net	—	24.2	306.9
Other Investing Activities	18.4	12.6	12.0
Net Cash Flows Used for Investing Activities	(707.5)	(530.9)	(97.3)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	392.8	—	—
Change in Advances from Affiliates, Net	26.3	87.8	—
Retirement of Long-term Debt – Nonaffiliated	(397.1)	(46.4)	(395.9)
Principal Payments for Capital Lease Obligations	(3.8)	(4.1)	(4.2)
Dividends Paid on Common Stock	(337.5)	(130.0)	(150.0)
Other Financing Activities	0.9	0.8	0.6
Net Cash Flows Used for Financing Activities	(318.4)	(91.9)	(549.5)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	2.8	(0.6)	(0.5)
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	29.7	30.3	30.8
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$ 32.5	$ 29.7	$ 30.3
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 97.1	$ 100.0	$ 109.9
Net Cash Paid for Income Taxes	51.3	48.5	220.4
Noncash Acquisitions Under Capital Leases	4.4	4.5	3.4
Construction Expenditures Included in Current Liabilities as of December 31,	98.2	87.8	44.6

See Notes to Financial Statements of Registrants beginning on page 175.

PUBLIC SERVICE COMPANY OF OKLAHOMA
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

COMPANY OVERVIEW

As a public utility, PSO engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 556,000 retail customers in its service territory in eastern and southwestern Oklahoma. PSO sells electric power at wholesale to other utilities, municipalities and electric cooperatives. PSO shares off-system sales margins with its customers.

AEPSC conducts power, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on PSO's behalf. PSO shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with SWEPCo. Power and natural gas risk management activities are allocated based on the Operating Agreement. Risk management activities primarily include power and natural gas and physical transactions, financially-settled swaps and exchange-traded futures. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM generally accruing to the benefit of APCo, I&M, KPCo and WPCo and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the common shareholder's equity of these companies.

PSO is jointly and severally liable for activity conducted by AEPSC on the behalf of PSO and SWEPCo related to power purchase and sale activity.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2018	**2017**	**2016**
	(in millions of KWhs)		
Retail:			
Residential	6,453	5,943	6,229
Commercial	5,170	5,175	5,265
Industrial	5,958	5,669	5,534
Miscellaneous	1,259	1,239	1,257
Total Retail	18,840	18,026	18,285
Wholesale	758	355	298
Total KWhs	19,598	18,381	18,583

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2018	**2017**	**2016**
	(in degree days)		
Actual – Heating (a)	1,886	1,249	1,341
Normal – Heating (b)	1,752	1,776	1,778
Actual – Cooling (c)	2,445	2,131	2,444
Normal – Cooling (b)	2,149	2,147	2,132

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Cooling degree days are calculated on a 65 degree temperature base.

2018 Compared to 2017

Reconciliation of Year Ended December 31, 2017 to Year Ended December 31, 2018
Net Income
(in millions)

Year Ended December 31, 2017	$	72.0
Changes in Gross Margin:		
Retail Margins (a)		47.2
Off-system Sales		1.3
Transmission Revenues		1.4
Other Revenues		(0.8)
Total Change in Gross Margin		49.1
Changes in Expenses and Other:		
Other Operation and Maintenance		(42.2)
Depreciation and Amortization		(33.6)
Taxes Other Than Income Taxes		(2.3)
Allowance for Funds Used During Construction		(0.1)
Non-Service Cost Components of Net Periodic Benefit Cost		5.3
Interest Expense		(10.1)
Total Change in Expenses and Other		(83.0)
Income Tax Expense		45.1
Year Ended December 31, 2018	$	83.2

(a) Includes firm wholesale sales to municipals and cooperatives.

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** increased $47 million primarily due to the following:
  - A $52 million increase due to new base rates implemented in March 2018, inclusive of a $27 million decrease due to the change in the corporate federal tax rate.
  - A $30 million increase in weather-related usage due to a 51% increase in heating degree days and a 15% increase in cooling degree days.
  - A $22 million increase in revenue from rate riders. This increase was partially offset by corresponding increases in other expense items below.

These increases were partially offset by:
  - A $24 million decrease due to 2018 customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.
  - A $16 million decrease related to the System Reliability Rider (SRR) that ended in August 2017. This decrease was partially offset by a corresponding decrease recognized in other expense items below.
  - A $16 million decrease due to lower weather-normalized margins.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses increased $42 million primarily due to the following:
  - A $41 million increase in transmission expenses primarily due to increased SPP transmission services.
  - A $12 million increase in Energy Efficiency program costs. This increase was offset by an increase from rate riders in Retail Margins above.
  - An $8 million increase due to the Wind Catcher Project.
  - A $5 million increase in generation expenses including employee-related expenses.

These increases were partially offset by:

- A $13 million decrease in distribution expenses primarily due to the amortization of previously deferred vegetation management costs collected through the SRR. This decrease was partially offset by a corresponding decrease in Retail Margins above.
- An $11 million decrease due to a refund associated with SPP transmission expenses incurred in prior periods.

- **Depreciation and Amortization** expenses increased $34 million primarily due to higher depreciable base and new rates implemented in March 2018.
- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $5 million primarily due to favorable asset returns for the funded Pension and OPEB plans, favorable OPEB cost savings arrangements and the implementation of ASU 2017-07.
- **Interest Expense** increased $10 million primarily due to the 2017 deferral of the debt components of carrying charges on environmental control costs for projects at Northeastern Plant, Unit 3 and Comanche Plant.
- **Income Tax Expense** decreased $45 million primarily due to the change in the corporate federal income tax rate from 35% in 2017 to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Public Service Company of Oklahoma

Opinion on the Financial Statements

We have audited the accompanying balance sheets of Public Service Company of Oklahoma (the "Company") as of December 31, 2018 and 2017, and the related statements of income, comprehensive income (loss), changes in common shareholder's equity, and cash flows for each of the two years in the period ended December 31, 2018, including the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 21, 2019

We have served as the Company's auditor since 2017.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Public Service Company of Oklahoma:

We have audited the accompanying statements of income, comprehensive income (loss), changes in common shareholder's equity, and cash flows of Public Service Company of Oklahoma (the "Company") for the year ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the results of operations and cash flows of Public Service Company of Oklahoma for the year ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2017

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Public Service Company of Oklahoma (PSO) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. PSO's internal control is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of PSO's internal control over financial reporting as of December 31, 2018. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded PSO's internal control over financial reporting was effective as of December 31, 2018.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, PSO's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit PSO to provide only management's report in this annual report.

SCHEDULE E-5

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF INCOME
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31,		
	2018	**2017**	**2016**
REVENUES			
Electric Generation, Transmission and Distribution	$ 1,537.6	$ 1,417.5	$ 1,242.8
Sales to AEP Affiliates	5.4	4.3	2.6
Other Revenues	4.3	5.4	4.4
TOTAL REVENUES	1,547.3	1,427.2	1,249.8
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	240.5	134.5	44.8
Purchased Electricity for Resale	479.9	514.9	441.2
Purchased Electricity from AEP Affiliates	—	—	3.7
Other Operation	372.8	315.1	291.6
Maintenance	104.8	120.3	106.9
Depreciation and Amortization	164.0	130.4	130.2
Taxes Other Than Income Taxes	42.8	40.5	35.8
TOTAL EXPENSES	1,404.8	1,255.7	1,054.2
OPERATING INCOME	142.5	171.5	195.6
Other Income (Expense):			
Interest Income	0.1	0.1	0.7
Allowance for Equity Funds Used During Construction	0.4	0.5	6.2
Non-Service Cost Components of Net Periodic Benefit Cost	8.7	3.4	3.1
Interest Expense	(63.5)	(53.4)	(51.2)
INCOME BEFORE INCOME TAX EXPENSE	88.2	122.1	154.4
Income Tax Expense	5.0	50.1	54.4
NET INCOME	$ 83.2	$ 72.0	$ 100.0

The common stock of PSO is wholly-owned by Parent.

See Notes to Financial Statements of Registrants beginning on page 175.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31,		
	2018	**2017**	**2016**
Net Income	$ 83.2	$ 72.0	$ 100.0
OTHER COMPREHENSIVE LOSS, NET OF TAXES			
Cash Flow Hedges, Net of Tax of $(0.3), $(0.4) and $(0.4) in 2018, 2017 and 2016, Respectively	(1.0)	(0.8)	(0.8)
TOTAL COMPREHENSIVE INCOME	$ 82.2	$ 71.2	$ 99.2

See Notes to Financial Statements of Registrants beginning on page 175.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2015	$ 157.2	$ 364.0	$ 594.5	$ 4.2	$ 1,119.9
Common Stock Dividends			(5.0)		(5.0)
Net Income			100.0		100.0
Other Comprehensive Loss				(0.8)	(0.8)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	157.2	364.0	689.5	3.4	1,214.1
Common Stock Dividends			(70.0)		(70.0)
Net Income			72.0		72.0
Other Comprehensive Loss				(0.8)	(0.8)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	157.2	364.0	691.5	2.6	1,215.3
Common Stock Dividends			(50.0)		(50.0)
ASU 2018-02 Adoption				0.5	0.5
Net Income			83.2		83.2
Other Comprehensive Loss				(1.0)	(1.0)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	$ 157.2	$ 364.0	$ 724.7	$ 2.1	$ 1,248.0

See Notes to Financial Statements of Registrants beginning on page 175.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
ASSETS
December 31, 2018 and 2017
(in millions)

	December 31, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2.0	$ 1.6
Accounts Receivable:		
Customers	32.5	32.5
Affiliated Companies	26.2	32.9
Miscellaneous	5.7	4.1
Allowance for Uncollectible Accounts	(0.1)	(0.1)
Total Accounts Receivable	64.3	69.4
Fuel	12.3	12.5
Materials and Supplies	44.8	42.0
Risk Management Assets	10.4	6.4
Accrued Tax Benefits	14.7	28.1
Regulatory Asset for Under-Recovered Fuel Costs	—	36.7
Prepayments and Other Current Assets	9.4	8.6
TOTAL CURRENT ASSETS	157.9	205.3
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,577.0	1,577.2
Transmission	892.3	858.8
Distribution	2,572.8	2,445.1
Other Property, Plant and Equipment	303.5	287.4
Construction Work in Progress	94.0	111.3
Total Property, Plant and Equipment	5,439.6	5,279.8
Accumulated Depreciation and Amortization	1,472.9	1,393.6
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	3,966.7	3,886.2
OTHER NONCURRENT ASSETS		
Regulatory Assets	369.0	368.1
Employee Benefits and Pension Assets	31.7	40.0
Deferred Charges and Other Noncurrent Assets	7.1	8.7
TOTAL OTHER NONCURRENT ASSETS	407.8	416.8
TOTAL ASSETS	$ 4,532.4	$ 4,508.3

See Notes to Financial Statements of Registrants beginning on page 175.

PUBLIC SERVICE COMPANY OF OKLAHOMA
BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2018 and 2017

	December 31, 2018	December 31, 2017
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 105.5	$ 149.6
Accounts Payable:		
General	126.9	102.4
Affiliated Companies	47.1	48.0
Long-term Debt Due Within One Year – Nonaffiliated	375.5	0.5
Risk Management Liabilities	1.0	—
Customer Deposits	58.6	54.1
Accrued Taxes	22.4	22.6
Accrued Interest	13.9	14.1
Regulatory Liability for Over-Recovered Fuel Costs	20.1	—
Other Current Liabilities	50.6	44.7
TOTAL CURRENT LIABILITIES	821.6	436.0
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	911.5	1,286.0
Deferred Income Taxes	607.8	642.0
Regulatory Liabilities and Deferred Investment Tax Credits	864.7	853.5
Asset Retirement Obligations	46.3	53.0
Deferred Credits and Other Noncurrent Liabilities	32.5	22.5
TOTAL NONCURRENT LIABILITIES	2,462.8	2,857.0
TOTAL LIABILITIES	3,284.4	3,293.0
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $15 Per Share:		
Authorized – 11,000,000 Shares		
Issued – 10,482,000 Shares		
Outstanding – 9,013,000 Shares	157.2	157.2
Paid-in Capital	364.0	364.0
Retained Earnings	724.7	691.5
Accumulated Other Comprehensive Income (Loss)	2.1	2.6
TOTAL COMMON SHAREHOLDER'S EQUITY	1,248.0	1,215.3
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 4,532.4	$ 4,508.3

See Notes to Financial Statements of Registrants beginning on page 175.

PUBLIC SERVICE COMPANY OF OKLAHOMA
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31, 2018	2017	2016
OPERATING ACTIVITIES			
Net Income	$ 83.2	$ 72.0	$ 100.0
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	164.0	130.4	130.2
Deferred Income Taxes	(31.1)	124.7	82.5
Allowance for Equity Funds Used During Construction	(0.4)	(0.5)	(6.2)
Mark-to-Market of Risk Management Contracts	(3.0)	(5.6)	(0.4)
Pension Contributions to Qualified Plan Trust	—	(5.3)	(5.6)
Deferred Fuel Over/Under-Recovery, Net	57.4	(5.4)	(109.9)
Provision for Refund, Net	3.8	(43.5)	46.1
Change in Other Noncurrent Assets	—	(27.2)	(35.9)
Change in Other Noncurrent Liabilities	17.6	4.5	(0.1)
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	5.1	(10.9)	(9.0)
Fuel, Materials and Supplies	(2.6)	13.0	2.0
Accounts Payable	17.7	(10.7)	25.7
Accrued Taxes, Net	13.2	0.8	7.4
Other Current Assets	(0.8)	(2.1)	0.8
Other Current Liabilities	6.4	3.9	(10.4)
Net Cash Flows from Operating Activities	330.5	238.1	217.2
INVESTING ACTIVITIES			
Construction Expenditures	(240.2)	(266.1)	(351.1)
Change in Advances to Affiliates, Net	—	—	80.6
Other Investing Activities	7.2	4.6	11.0
Net Cash Flows Used for Investing Activities	(233.0)	(261.5)	(259.5)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	—	—	274.2
Change in Advances from Affiliates, Net	(44.1)	97.6	52.0
Retirement of Long-term Debt – Nonaffiliated	(0.5)	(0.5)	(275.4)
Dividends Paid on Common Stock	(50.0)	(70.0)	(5.0)
Other Financing Activities	(2.5)	(3.6)	(3.4)
Net Cash Flows from (Used for) Financing Activities	(97.1)	23.5	42.4
Net Increase in Cash and Cash Equivalents	0.4	0.1	0.1
Cash and Cash Equivalents at Beginning of Period	1.6	1.5	1.4
Cash and Cash Equivalents at End of Period	$ 2.0	$ 1.6	$ 1.5
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 62.0	$ 61.5	$ 60.1
Net Cash Paid (Received) for Income Taxes	17.9	(72.6)	(37.7)
Noncash Acquisitions Under Capital Leases	4.3	2.1	3.1
Construction Expenditures Included in Current Liabilities as of December 31,	33.2	23.1	33.6

See Notes to Financial Statements of Registrants beginning on page 175.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

COMPANY OVERVIEW

As a public utility, SWEPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 537,000 retail customers in its service territory in northeastern and the panhandle of Texas, northwestern Louisiana and western Arkansas. SWEPCo consolidates its wholly-owned subsidiary, Southwest Arkansas Utilities Corporation. SWEPCo also consolidates Sabine Mining Company, a variable interest entity. SWEPCo sells electric power at wholesale to other utilities, municipalities and electric cooperatives. SWEPCo shares off-system sales margins with its customers.

AEPSC conducts power, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on SWEPCo's behalf. SWEPCo shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with PSO. Power and natural gas risk management activities are allocated based on the Operating Agreement. Risk management activities primarily include power and natural gas and physical transactions, financially-settled swaps and exchange-traded futures. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM generally accruing to the benefit of APCo, I&M, KPCo and WPCo and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the common shareholder's equity of these companies.

SWEPCo is jointly and severally liable for activity conducted by AEPSC on the behalf of PSO and SWEPCo related to power purchase and sale activity.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2018	**2017**	**2016**
	(in millions of KWhs)		
Retail:			
Residential	6,564	5,903	6,148
Commercial	6,007	5,895	6,064
Industrial	5,295	5,268	5,074
Miscellaneous	79	81	81
Total Retail	17,945	17,147	17,367
Wholesale	7,071	8,324	8,069
Total KWhs	25,016	25,471	25,436

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2018	**2017**	**2016**
	(in degree days)		
Actual – Heating (a)	1,308	829	917
Normal – Heating (b)	1,195	1,208	1,208
Actual – Cooling (c)	2,560	2,197	2,516
Normal – Cooling (b)	2,311	2,312	2,298

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Cooling degree days are calculated on a 65 degree temperature base.

2018 Compared to 2017

Reconciliation of Year Ended December 31, 2017 to Year Ended December 31, 2018
Earnings Attributable to SWEPCo Common Shareholder
(in millions)

Year Ended December 31, 2017	$	124.7
Changes in Gross Margin:		
Retail Margins (a)		13.6
Off-system Sales		(0.8)
Transmission Revenues		8.8
Other Revenues		5.8
Total Change in Gross Margin		27.4
Changes in Expenses and Other:		
Other Operation and Maintenance		(63.9)
Asset Impairments and Other Related Charges		33.6
Depreciation and Amortization		(22.1)
Taxes Other Than Income Taxes		(1.3)
Interest Income		2.7
Allowance for Equity Funds Used During Construction		3.6
Non-Service Cost Components of Net Periodic Benefit Cost		5.0
Interest Expense		(4.5)
Total Change in Expenses and Other		(46.9)
Income Tax Expense		27.7
Equity Earnings (Loss) of Unconsolidated Subsidiary		6.5
Net Income Attributable to Noncontrolling Interest		7.8
Year Ended December 31, 2018	$	147.2

(a) Includes firm wholesale sales to municipals and cooperatives.

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** increased $14 million primarily due to the following:
  - A $49 million increase in weather-related usage primarily due to a 58% increase in heating degree days and a 17% increase in cooling degree days.
  - A $44 million increase primarily due to rider and base rate revenue increases in Texas, Louisiana and Arkansas, partially offset in various expenses below.
  - A $4 million increase due to higher fuel cost recovery.

  These increases were partially offset by:
  - A $49 million decrease in weather-normalized margins, primarily due to wholesale customer load loss from contracts that expired at the end of 2017.
  - A $36 million decrease due to the 2018 provisions for customer refunds related to Tax Reform. This decrease was offset in Income Tax Expense below.

- **Transmission Revenues** increased $9 million primarily due to a $25 million increase from continued SPP transmission investments, partially offset by a $16 million decrease from a 2018 provision for refund related to revenues recorded in prior periods on certain transmission assets that management believes should not have been included in the SPP formula rate.
- **Other Revenues** increased $6 million due to the 2017 Louisiana Turk Plant Prudence Review settlement.

Expenses and Other, Income Tax Expense, Equity Earnings (Loss) of Unconsolidated Subsidiary and Net Income Attributable to Noncontrolling Interest changed between years as follows:

- **Other Operation and Maintenance** expenses increased $64 million primarily due to the following:
    - A $19 million increase due to the Wind Catcher Project.
    - A $13 million increase in SPP transmission services.
    - A $10 million increase in Energy Efficiency program costs. This increase was offset by an increase from rate riders in Retail Margins above.
    - A $9 million increase due to a gain recognized on the sale of property in 2017.
    - A $5 million increase in employee-related expenses.
- **Asset Impairments and Other Related Charges** decreased $34 million due to Welsh Plant, Unit 2 and Turk Plant asset impairments and other charges related to the 2016 Texas Base Rate Case and the 2017 Louisiana Turk Plant Prudence Review.
- **Depreciation and Amortization** expenses increased $22 million primarily due to a higher depreciable base and higher depreciation rates approved in the 2017 Louisiana Formula Rate Filing and the 2016 Texas Base Rate Case.
- **Allowance for Equity Funds Used During Construction** increased $4 million primarily due to higher average CWIP balances.
- **Non-Service Cost Components of Net Periodic Benefit Cost** decreased $5 million primarily due to favorable asset returns for the funded Pension and OPEB plans, favorable OPEB cost savings arrangements and the implementation of ASU 2017-07.
- **Interest Expense** increased $5 million primarily due to interest expense credits in 2017 on Welsh Plant and Flint Creek Plant environmental project deferrals and other interest expense accruals for refunds and true-ups in 2018.
- **Income Tax Expense** decreased $28 million primarily due to the change in the corporate federal income tax rate from 35% to 21% in 2018 as a result of Tax Reform, amortization of Excess ADIT and a decrease in pretax book income.
- **Equity Earnings (Loss) of Unconsolidated Subsidiary** increased $7 million primarily due to a prior period income tax adjustment recognized in 2017.
- **Net Income Attributable to Noncontrolling Interest** decreased $8 million primarily due to 2017 income tax benefits attributable to SWEPCo's noncontrolling interest in Sabine. This decrease was offset by an increase in Income Tax Expense above.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Southwestern Electric Power Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Southwestern Electric Power Company and its subsidiaries (the "Company") as of December 31, 2018 and 2017, and the related consolidated statements of income, comprehensive income (loss), changes in equity, and cash flows for each of the two years in the period ended December 31, 2018, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 21, 2019

We have served as the Company's auditor since 2017.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Southwestern Electric Power Company:

We have audited the accompanying consolidated statements of income, comprehensive income (loss), changes in equity, and cash flows of Southwestern Electric Power Company and subsidiaries (the "Company") for the year ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the results of operations and cash flows of Southwestern Electric Power Company and subsidiaries for the year ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 27, 2017

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Southwestern Electric Power Company Consolidated (SWEPCo) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. SWEPCo's internal control is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of SWEPCo's internal control over financial reporting as of December 31, 2018. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded SWEPCo's internal control over financial reporting was effective as of December 31, 2018.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, SWEPCo's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit SWEPCo to provide only management's report in this annual report.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31,		
	2018	**2017**	**2016**
REVENUES			
Electric Generation, Transmission and Distribution	$ 1,791.9	$ 1,752.1	$ 1,721.5
Sales to AEP Affiliates	28.4	25.9	24.5
Other Revenues	1.6	1.9	2.0
TOTAL REVENUES	1,821.9	1,779.9	1,748.0
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	502.3	496.1	517.8
Purchased Electricity for Resale	177.1	168.7	142.4
Other Operation	384.2	318.3	335.4
Maintenance	141.5	143.5	149.7
Asset Impairments and Other Related Charges	—	33.6	—
Depreciation and Amortization	239.5	217.4	196.5
Taxes Other Than Income Taxes	99.6	98.3	88.8
TOTAL EXPENSES	1,544.2	1,475.9	1,430.6
OPERATING INCOME	277.7	304.0	317.4
Other Income (Expense):			
Interest Income	5.4	2.7	1.5
Allowance for Equity Funds Used During Construction	6.0	2.4	11.0
Non-Service Cost Components of Net Periodic Benefit Cost	8.7	3.7	3.7
Interest Expense	(127.9)	(123.4)	(119.7)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS (LOSS)	169.9	189.4	213.9
Income Tax Expense	20.4	48.1	52.1
Equity Earnings (Loss) of Unconsolidated Subsidiary	2.7	(3.8)	7.9
NET INCOME	152.2	137.5	169.7
Net Income Attributable to Noncontrolling Interest	5.0	12.8	4.1
EARNINGS ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 147.2	$ 124.7	$ 165.6

The common stock of SWEPCo is wholly-owned by Parent.

See Notes to Financial Statements of Registrants beginning on page 175.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31,		
	2018	**2017**	**2016**
Net Income	$ 152.2	$ 137.5	$ 169.7
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $1.1, $0.8 and $0.9 in 2018, 2017 and 2016, Respectively	4.0	1.4	1.7
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.4), $(0.4) and $(0.4) in 2018, 2017 and 2016, Respectively	(1.4)	(0.7)	(0.7)
Pension and OPEB Funded Status, Net of Tax of $(0.8), $2.5 and $(0.5) in 2018, 2017 and 2016, Respectively	(3.1)	4.7	(1.0)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(0.5)	5.4	—
TOTAL COMPREHENSIVE INCOME	151.7	142.9	169.7
Total Comprehensive Income Attributable to Noncontrolling Interest	5.0	12.8	4.1
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO SWEPCo COMMON SHAREHOLDER	$ 146.7	$ 130.1	$ 165.6

See Notes to Financial Statements of Registrants beginning on page 175.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	SWEPCo Common Shareholder					
	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
TOTAL EQUITY – DECEMBER 31, 2015	$ 135.7	$ 676.6	$ 1,366.3	$ (9.4)	$ 0.5	$ 2,169.7
Common Stock Dividends			(120.0)			(120.0)
Common Stock Dividends – Nonaffiliated					(4.2)	(4.2)
Net Income			165.6		4.1	169.7
TOTAL EQUITY – DECEMBER 31, 2016	135.7	676.6	1,411.9	(9.4)	0.4	2,215.2
Common Stock Dividends			(110.0)			(110.0)
Common Stock Dividends – Nonaffiliated					(13.6)	(13.6)
Net Income			124.7		12.8	137.5
Other Comprehensive Income				5.4		5.4
TOTAL EQUITY – DECEMBER 31, 2017	135.7	676.6	1,426.6	(4.0)	(0.4)	2,234.5
Common Stock Dividends			(65.0)			(65.0)
Common Stock Dividends – Nonaffiliated					(4.3)	(4.3)
ASU 2018-02 Adoption			(0.4)	(0.9)		(1.3)
Net Income			147.2		5.0	152.2
Other Comprehensive Loss				(0.5)		(0.5)
TOTAL EQUITY – DECEMBER 31, 2018	$ 135.7	$ 676.6	$ 1,508.4	$ (5.4)	$ 0.3	$ 2,315.6

See Notes to Financial Statements of Registrants beginning on page 175.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2018 and 2017
(in millions)

	December 31, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents (December 31, 2018 and 2017 Amounts Include $22 and $0, Respectively, Related to Sabine)	$ 24.5	$ 1.6
Advances to Affiliates	83.4	2.0
Accounts Receivable:		
Customers	24.5	70.9
Affiliated Companies	28.8	30.2
Miscellaneous	20.2	25.8
Allowance for Uncollectible Accounts	(0.7)	(1.3)
Total Accounts Receivable	72.8	125.6
Fuel (December 31, 2018 and 2017 Amounts Include $35.7 and $41.5, Respectively, Related to Sabine)	120.5	123.6
Materials and Supplies	67.5	67.9
Risk Management Assets	4.8	6.4
Regulatory Asset for Under-Recovered Fuel Costs	18.8	14.1
Prepayments and Other Current Assets	22.2	39.2
TOTAL CURRENT ASSETS	414.5	380.4
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	4,672.6	4,624.9
Transmission	1,866.9	1,679.8
Distribution	2,178.6	2,095.8
Other Property, Plant and Equipment (December 31, 2018 and 2017 Amounts Include $276.9 and $266.7, Respectively, Related to Sabine)	762.7	684.1
Construction Work in Progress	199.3	233.2
Total Property, Plant and Equipment	9,680.1	9,317.8
Accumulated Depreciation and Amortization (December 31, 2018 and 2017 Amounts Include $174.6 and $165.9, Respectively, Related to Sabine)	2,808.3	2,685.8
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	6,871.8	6,632.0
OTHER NONCURRENT ASSETS		
Regulatory Assets	230.8	220.6
Deferred Charges and Other Noncurrent Assets	111.2	109.9
TOTAL OTHER NONCURRENT ASSETS	342.0	330.5
TOTAL ASSETS	$ 7,628.3	$ 7,342.9

See Notes to Financial Statements of Registrants beginning on page 175.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2018 and 2017

	December 31, 2018	December 31, 2017
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ —	$ 118.7
Accounts Payable:		
General	129.1	160.4
Affiliated Companies	64.2	63.7
Short-term Debt – Nonaffiliated	—	22.0
Long-term Debt Due Within One Year – Nonaffiliated	59.7	3.7
Risk Management Liabilities	0.4	0.2
Customer Deposits	64.5	62.1
Accrued Taxes	42.8	39.0
Accrued Interest	34.7	38.9
Obligations Under Capital Leases	10.2	11.2
Other Current Liabilities	107.3	78.7
TOTAL CURRENT LIABILITIES	512.9	598.6
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	2,653.7	2,438.2
Long-term Risk Management Liabilities	2.2	—
Deferred Income Taxes	902.8	917.7
Regulatory Liabilities and Deferred Investment Tax Credits	923.0	896.4
Asset Retirement Obligations	191.3	160.3
Employee Benefits and Pension Obligations	24.8	19.5
Obligations Under Capital Leases	50.6	57.8
Deferred Credits and Other Noncurrent Liabilities	51.4	19.9
TOTAL NONCURRENT LIABILITIES	4,799.8	4,509.8
TOTAL LIABILITIES	5,312.7	5,108.4
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
EQUITY		
Common Stock – Par Value – $18 Per Share:		
Authorized – 7,600,000 Shares		
Outstanding – 7,536,640 Shares	135.7	135.7
Paid-in Capital	676.6	676.6
Retained Earnings	1,508.4	1,426.6
Accumulated Other Comprehensive Income (Loss)	(5.4)	(4.0)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,315.3	2,234.9
Noncontrolling Interest	0.3	(0.4)
TOTAL EQUITY	2,315.6	2,234.5
TOTAL LIABILITIES AND EQUITY	$ 7,628.3	$ 7,342.9

See Notes to Financial Statements of Registrants beginning on page 175.

SOUTHWESTERN ELECTRIC POWER COMPANY CONSOLIDATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2018, 2017 and 2016
(in millions)

	Years Ended December 31, 2018	2017	2016
OPERATING ACTIVITIES			
Net Income	$ 152.2	$ 137.5	$ 169.7
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	239.5	217.4	196.5
Deferred Income Taxes	1.2	80.5	162.6
Asset Impairments and Other Related Charges	—	33.6	—
Allowance for Equity Funds Used During Construction	(6.0)	(2.4)	(11.0)
Mark-to-Market of Risk Management Contracts	4.0	(5.6)	(5.1)
Pension Contributions to Qualified Plan Trust	—	(8.9)	(8.3)
Deferred Fuel Over/Under-Recovery, Net	(2.4)	(0.8)	(8.9)
Change in Regulatory Liabilities	(3.8)	(12.3)	(22.0)
Change in Other Noncurrent Assets	(18.8)	(9.2)	(13.0)
Change in Other Noncurrent Liabilities	46.6	17.0	6.0
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	53.5	(32.9)	(5.7)
Fuel, Materials and Supplies	3.5	(16.0)	38.1
Accounts Payable	0.9	10.5	3.5
Accrued Taxes, Net	2.3	45.7	(68.9)
Other Current Assets	15.6	5.2	(13.9)
Other Current Liabilities	16.5	(14.6)	(15.3)
Net Cash Flows from Operating Activities	504.8	444.7	404.3
INVESTING ACTIVITIES			
Construction Expenditures	(451.0)	(404.1)	(426.3)
Change in Advances to Affiliates, Net	(81.4)	167.8	(167.8)
Proceeds from Sales of Assets	1.4	12.6	1.1
Other Investing Activities	2.1	3.1	(1.0)
Net Cash Flows Used for Investing Activities	(528.9)	(220.6)	(594.0)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	1,065.7	114.6	406.7
Change in Short-term Debt, Net – Nonaffiliated	(22.0)	22.0	—
Change in Advances from Affiliates, Net	(118.7)	118.7	(58.3)
Retirement of Long-term Debt – Nonaffiliated	(794.5)	(353.7)	(3.3)
Principal Payments for Capital Lease Obligations	(11.5)	(11.3)	(27.1)
Dividends Paid on Common Stock	(65.0)	(110.0)	(120.0)
Dividends Paid on Common Stock – Nonaffiliated	(4.3)	(13.6)	(4.2)
Other Financing Activities	(2.7)	0.5	1.0
Net Cash Flows from (Used for) Financing Activities	47.0	(232.8)	194.8
Net Increase (Decrease) in Cash and Cash Equivalents	22.9	(8.7)	5.1
Cash and Cash Equivalents at Beginning of Period	1.6	10.3	5.2
Cash and Cash Equivalents at End of Period	$ 24.5	$ 1.6	$ 10.3
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 125.7	$ 124.4	$ 118.0
Net Cash Paid (Received) for Income Taxes	18.8	(75.3)	(32.0)
Noncash Acquisitions Under Capital Leases	3.6	3.3	5.9
Construction Expenditures Included in Current Liabilities as of December 31,	42.0	71.2	41.8

See Notes to Financial Statements of Registrants beginning on page 175.

INDEX OF NOTES TO FINANCIAL STATEMENTS OF REGISTRANTS

The notes to financial statements are a combined presentation for the Registrants. The following list indicates Registrants to which the notes apply. Specific disclosures within each note apply to all Registrants unless indicated otherwise.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The disclosures in this note apply to all Registrants unless indicated otherwise.

ORGANIZATION

The Registrants engage in the generation, transmission and distribution of electric power. The Registrant Subsidiaries that conduct most of these activities are regulated by the FERC under the Federal Power Act and the Energy Policy Act of 2005 and maintain accounts in accordance with the FERC and other regulatory guidelines. Most of these companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

AEP provides competitive electric and gas supply for residential, commercial and industrial customers in deregulated electricity markets and also provides energy management solutions throughout the United States, including energy efficiency services through its independent retail electric supplier.

The Registrants also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States and provide various energy-related services. In addition, AEP operates competitive wind and solar farms. I&M provides barging services to both affiliated and nonaffiliated companies. SWEPCo, through consolidated and nonconsolidated affiliates, conducts lignite mining operations to fuel certain of its generation facilities.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

AEP's public utility subsidiaries' rates are regulated by the FERC and state regulatory commissions in the eleven state operating territories in which they operate. The FERC also regulates the Registrants' affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of the public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. For non-power goods and services, the FERC requires a nonregulated affiliate to bill an affiliated public utility company at no more than market while a public utility must bill the higher of cost or market to a nonregulated affiliate. The state regulatory commissions also regulate certain intercompany transactions under various orders and affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

The FERC regulates wholesale power markets and wholesale power transactions. The Registrants' wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when a cost-based contract is negotiated and filed with the FERC or the FERC determines that the Registrants have "market power" in the region where the transaction occurs. Wholesale power supply contracts have been entered into with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued up to actual costs annually.

The state regulatory commissions regulate all of the retail distribution operations and rates of the Registrants' retail public utility subsidiaries on a cost basis. The state regulatory commissions also regulate the retail generation/power supply operations and rates except in Ohio and the ERCOT region of Texas. For generation in Ohio, customers who have not switched to a CRES provider for generation pay market-based auction rates. In addition, all OPCo distribution customers pay for certain deferred generation-related costs through non-bypassable charges. In the ERCOT region of Texas, the generation/supply business is under customer choice and market pricing is conducted by REPs. AEP has no active REPs in ERCOT. AEP's nonregulated subsidiaries enter into short and long-term wholesale transactions to buy or sell capacity, energy and ancillary services in the ERCOT market. In addition, these nonregulated subsidiaries control certain wind and coal-fired generation assets, the power from which is marketed and sold in ERCOT.

The FERC also regulates the Registrants' wholesale transmission operations and rates. Retail transmission rates are based upon the FERC OATT rate when retail rates are unbundled in connection with restructuring. Retail transmission rates are based on formula rates included in the PJM OATT that are cost-based and are unbundled in Ohio for OPCo,

in Virginia for APCo and in Michigan for I&M. AEP Texas' retail transmission rates in Texas are unbundled but the retail transmission rates are regulated, on a cost basis, by the PUCT. Bundled retail transmission rates are regulated, on a cost basis, by the state commissions. Transmission rates for AEPTCo's seven wholly-owned transmission subsidiaries within the AEP Transmission Holdco segment are based on formula rates included in the applicable RTO's OATT that are cost-based.

In West Virginia, APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC, with rates set on a combined cost-of-service basis.

In addition, the FERC regulates the SIA, Operating Agreement, Transmission Agreement and Transmission Coordination Agreement, all of which allocate shared system costs and revenues among the utility subsidiaries that are parties to each agreement. The FERC also regulates the PCA and the Bridge Agreement, see Note 16 - Related Party Transactions for additional information.

Principles of Consolidation

AEP's consolidated financial statements include its wholly-owned and majority-owned subsidiaries and VIEs of which AEP is the primary beneficiary. The consolidated financial statements for AEP Texas include the Registrant Subsidiary, its wholly-owned subsidiaries and Transition Funding (consolidated VIEs). The consolidated financial statements for APCo include the Registrant Subsidiary, its wholly-owned subsidiaries and Appalachian Consumer Rate Relief Funding (a consolidated VIE). The consolidated financial statements for I&M include the Registrant Subsidiary, its wholly-owned subsidiaries and DCC Fuel (consolidated VIEs). The consolidated financial statements for OPCo include the Registrant Subsidiary and Ohio Phase-in-Recovery Funding (a consolidated VIE). The consolidated financial statements for SWEPCo include the Registrant Subsidiary, its wholly-owned subsidiary and Sabine (a consolidated VIE). Intercompany items are eliminated in consolidation.

The equity method of accounting is used for equity investments where the Registrants exercise significant influence but do not hold a controlling financial interest. Such investments are initially recorded at cost in Deferred Charges and Other Noncurrent Assets on the balance sheets. The proportionate share of the investee's equity earnings or losses is included in Equity Earnings of Unconsolidated Subsidiaries on the statements of income. AEP, AEP Texas, I&M, PSO and SWEPCo have ownership interests in generating units that are jointly-owned. The proportionate share of the operating costs associated with such facilities is included on the income statements and the assets and liabilities are reflected on the balance sheets. See Note 17 - Variable Interest Entities and Note 18 - Property, Plant and Equipment.

Accounting for the Effects of Cost-Based Regulation

The Registrants' financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for "Regulated Operations," regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

Use of Estimates

The preparation of these financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include, but are not limited to, inventory valuation, allowance for doubtful accounts, goodwill, intangible and long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, storm costs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

Restricted Cash (Applies to AEP, AEP Texas, APCo and OPCo)

Restricted Cash primarily includes funds held by trustees for the payment of securitization bonds.

Reconciliation of Cash, Cash Equivalents and Restricted Cash

The following tables provide a reconciliation of Cash, Cash Equivalents and Restricted Cash reported within the balance sheet that sum to the total of the same amounts shown on the statement of cash flows:

	December 31, 2018			
	AEP	AEP Texas	APCo	OPCo
	(in millions)			
Cash and Cash Equivalents	$ 234.1	$ 3.1	$ 4.2	$ 4.9
Restricted Cash	210.0	156.7	25.6	27.6
Total Cash, Cash Equivalents and Restricted Cash	$ 444.1	$ 159.8	$ 29.8	$ 32.5

	December 31, 2017			
	AEP	AEP Texas	APCo	OPCo
	(in millions)			
Cash and Cash Equivalents	$ 214.6	$ 2.0	$ 2.9	$ 3.1
Restricted Cash	198.0	155.2	16.3	26.6
Total Cash, Cash Equivalents and Restricted Cash	$ 412.6	$ 157.2	$ 19.2	$ 29.7

Other Temporary Investments (Applies to AEP)

Other Temporary Investments primarily include marketable securities and investments by its protected cell of EIS. These securities have readily determinable fair values and are carried at fair value with changes in fair value recognized in net income. The cost of securities sold is based on the specific identification or weighted-average cost method. See “Fair Value Measurements of Other Temporary Investments” section of Note 11 for additional information.

Inventory

Fossil fuel inventories are carried at average cost with the exception of AGR and AEP’s non-regulated ownership share of Oklaunion Plant, which is carried at the lower of average cost or market. Materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized over time as the performance obligations of delivering energy to customers are satisfied. To the extent that deliveries have occurred but a bill has not been issued, the Registrants accrue and recognize, as Accrued Unbilled Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, through purchase agreements with I&M, KGPCo, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo’s accounts receivable are sold to AEP Credit. AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from bank conduits for the interest in the billed and unbilled receivables they acquire from affiliated utility subsidiaries. See “Sale of Receivables – AEP Credit” section of Note 14 for additional information.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable purchased from participating AEP subsidiaries. For receivables related to APCo's West Virginia operations, the bad debt reserve is calculated based on a rolling two-year average write-off in proportion to gross accounts receivable. For customer accounts receivables relating to risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For AEP Texas, bad debt reserves are calculated using the specific identification of receivable balances greater than 120 days delinquent, and for those balances less than 120 days where the collection is doubtful. For miscellaneous accounts receivable, bad debt expense is recorded for all amounts outstanding 180 days or greater at 100%, unless specifically identified. Miscellaneous accounts receivable items open less than 180 days may be reserved using specific identification for bad debt reserves.

Concentrations of Credit Risk and Significant Customers (Applies to Registrant Subsidiaries)

APCo, I&M, OPCo, PSO and SWEPCo do not have any significant customers that comprise 10% or more of their operating revenues. AEP Texas had significant transactions with REPs which on a combined basis account for the following percentages of Total Revenues for the years ended December 31 and Accounts Receivable – Customers as of December 31:

Significant Customers of AEP Texas: Centrica, Just Energy, TXU Energy and Reliant Energy	**2018 (b)**	**2017 (a)(b)**	**2016 (a)**
Percentage of Total Revenues	45%	35%	46%
Percentage of Accounts Receivable – Customers	35%	31%	42%

(a) TXU Energy did not meet the Total Revenue threshold of 10% in order to be considered a significant customer.
(b) Just Energy did not meet the Total Revenue threshold of 10% in order to be considered a significant customer.

AEPTCo had significant transactions with AEP Subsidiaries which on a combined basis account for the following percentages of Total Revenues for the years ended December 31 and Total Accounts Receivable as of December 31:

Significant Customers of AEPTCo: AEP Subsidiaries	**2018**	**2017**	**2016**
Percentage of Total Revenues	77%	80%	77%
Percentage of Total Accounts Receivable	84%	85% (a)	86%

(a) Reflects the revisions made to AEPTCo's previously issued financial statements. See the "Revisions to Previously Issued Financial Statements" section of Note 1 for additional information.

The Registrant Subsidiaries monitor credit levels and the financial condition of their customers on a continuous basis to minimize credit risk. The regulatory commissions allow recovery in rates for a reasonable level of bad debt costs. Management believes adequate provisions for credit loss have been made in the accompanying Registrant Subsidiary financial statements.

Emission Allowances and Renewable Energy Credits (Applies to all Registrants except AEP Texas and AEPTCo)

In regulated jurisdictions, the Registrants record emission allowances and renewable energy credits (RECs) at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. For AEP's competitive generation business, management records allowances and RECs at the lower of cost or market. The Registrants follow the inventory model for these allowances and RECs. Allowances and RECs expected to be consumed within one year are reported in Materials and Supplies on the balance sheets. Allowances and RECs with expected consumption beyond one year are included in Deferred Charges and Other Noncurrent Assets on the balance sheets. The purchases and sales of allowances and RECs are reported in the Operating Activities section of the statements of cash flows. Allowances are consumed in the production of energy, and RECs are consumed to meet applicable state renewable portfolio standards and are recorded in Fuel and Other Consumables Used for Electric Generation at an average cost on the statements of income. The net margin on sales of emission allowances is included in Vertically Integrated Utilities Revenues on AEP's statements of income and in Electric Generation, Transmission

and Distribution Revenues on the Registrant Subsidiaries' statements of income because of its integral nature to the production process of energy and the Registrants' revenue optimization strategy for their operations. The net margin on sales of emission allowances and RECs affects the determination of deferred fuel or deferred emission allowance and REC costs and the amortization of regulatory assets for certain jurisdictions.

Property, Plant and Equipment

Regulated

Electric utility property, plant and equipment for rate-regulated operations are stated at original cost. Additions, major replacements and betterments are added to the plant accounts. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in original cost retirements, less salvage, being charged to accumulated depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of removal cost incurred and salvage received. These rates and the related lives are subject to periodic review. Removal costs accrued are typically recorded as regulatory liabilities when the revenue received for removal costs accrued exceeds actual removal costs incurred. The asset removal costs liability is relieved as removal costs are incurred. A regulatory asset balance will occur if actual removal costs incurred exceed accumulated removal costs accrued.

The costs of labor, materials and overhead incurred to operate and maintain plant and equipment are included in operating expenses.

Nuclear fuel, including nuclear fuel in the fabrication phase, is included in Other Property, Plant and Equipment on the balance sheets.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held-for-sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." When it becomes probable that an asset in service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed or is not probable, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense. The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Nonregulated

Nonregulated operations generally follow the policies of rate-regulated operations listed above but with the following exceptions. Property, plant and equipment of nonregulated operations are stated at original cost (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for most nonregulated operations under the group composite method of depreciation. A gain or loss would be recorded if the retirement is not considered an interim routine replacement. Removal costs are charged to expense.

Allowance for Funds Used During Construction and Interest Capitalization

For regulated operations, AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant. The Registrants record the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense. For nonregulated operations, including certain generating assets, interest is capitalized during construction in accordance with the accounting guidance for "Capitalization of Interest."

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Advances to/from Affiliates, Accounts Receivable, Accounts Payable and Short-term Debt approximate fair value because of the short-term maturity of these instruments.

Fair Value Measurements of Assets and Liabilities (Applies to all Registrants except AEPTCo)

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are nonbinding in nature but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A portion of the Level 3 instruments have been economically hedged which limits potential earnings volatility.

AEP utilizes its trustee's external pricing service to estimate the fair value of the underlying investments held in the benefit plan and nuclear trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's management performs its own valuation testing to verify the fair values of the securities. AEP receives audit reports of the trustee's operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the trusts.

Assets in the benefits and nuclear trusts, cash and cash equivalents, other temporary investments and restricted cash for securitized funding are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and equity securities. They are valued based on observable inputs, primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities. Fixed income securities generally do not trade on exchanges and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Investments

classified as Other are valued using Net Asset Value as a practical expedient. Items classified as Other are primarily cash equivalent funds, common collective trusts, commingled funds, structured products, private equity, real estate, infrastructure and alternative credit investments. These investments do not have a readily determinable fair value or they contain redemption restrictions which may include the right to suspend redemptions under certain circumstances. Redemption restrictions may also prevent certain investments from being redeemed at the reporting date for the underlying value.

Deferred Fuel Costs (Applies to all Registrants except AEP Texas and AEPTCo)

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the cost of nuclear fuel burned which is computed primarily using the units-of-production method. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel-related revenues over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel-related revenues) are generally deferred as current regulatory assets. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is a commission-approved plan to delay refunds or recoveries beyond a one year period. These deferrals are amortized when refunded or when billed to customers in later months with the state regulatory commissions' review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. On a routine basis, state regulatory commissions review and/or audit the Registrants' fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. FAC deferrals are adjusted when costs are no longer probable of recovery or when refunds of fuel reserves are probable.

Changes in fuel costs, including purchased power in Kentucky for KPCo, Indiana and Michigan for I&M, in Ohio (through the ESP related to SSO load served through auctions) for OPCo, in Arkansas, Louisiana and Texas for SWEPCo, in Oklahoma for PSO, in Virginia and West Virginia for APCo and in West Virginia for WPCo are reflected in rates in a timely manner generally through the FAC. In Ohio, changes in fuel costs incurred from 2009 through 2011, that continued to be recovered in rider rates were terminated in January 2019. The FAC generally includes some sharing of off-system sales margins. In West Virginia for APCo and WPCo, all of the non-merchant margins from off-system sales are given to customers through the FAC. A portion of margins from off-system sales are given to customers through the FAC and other rate mechanisms in Oklahoma for PSO, Arkansas, Louisiana and Texas for SWEPCo, Kentucky for KPCo, Virginia for APCo and in Indiana and Michigan for I&M. Where the FAC or off-system sales sharing mechanism is capped, frozen or non-existent, changes in fuel costs or sharing of off-system sales impact earnings.

Revenue Recognition

Regulatory Accounting

The Registrants' financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses or alternative revenues recognized in accordance with the guidance for "Regulated Operations") and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching revenue with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, assets are recorded on the balance sheets. Regulatory assets are tested for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, the regulatory asset is derecognized as a charge against income.

Retail and Wholesale Supply and Delivery of Electricity

The Registrants recognize revenues from customers for retail and wholesale electricity sales and electricity transmission and distribution delivery services. The Registrants recognize such revenues on the statements of income as the performance obligations of delivering energy to customers are satisfied. Recognized revenues include both billed and unbilled amounts. In accordance with the applicable state commission's regulatory treatment, PSO and SWEPCo do not include the fuel portion in unbilled revenue, but rather recognize such revenues when billed to customers.

Wholesale transmission revenue is based on FERC approved formula rate filings made for each calendar year using estimated costs. Revenues initially recognized per the annual rate filing are compared to actual costs, resulting in the subsequent recognition of an over or under recovered amount, with interest, that is refunded or recovered, respectively, in a future year's rates. These annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations", and are recognized by the Registrants in the second quarter following the filing of annual FERC reports. Any portion of the true-ups applicable to an affiliated company is recorded as Accounts Receivable - Affiliated Companies or Accounts Payable - Affiliated Companies on the balance sheets. Any portion of the true-ups applicable to third parties is recorded as Regulatory Assets or Regulatory Liabilities on the balance sheets. See Note 20 - Revenue from Contracts with Customers for additional information related to retail and wholesale revenues.

Gross versus Net Presentation of Certain Electricity Supply and Delivery Activities

Most of the power produced at the generation plants is sold to PJM or SPP. The Registrants also purchase power from PJM and SPP to supply power to customers. Generally, these power sales and purchases are reported on a net basis as revenues on the statements of income. However, purchases of power in excess of sales to PJM or SPP, on an hourly net basis, used to serve retail load are recorded gross as Purchased Electricity for Resale on the statements of income. With the exception of certain dedicated load bilateral power supply contracts, the transactions of AEP's nonregulated subsidiaries are reported as gross purchases or sales.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Purchased Electricity for Resale on the statements of income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's facts and circumstances. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Purchased Electricity for Resale on the statements of income. All other non-trading derivative purchases are recorded net in revenues.

In general, the Registrants record expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities (Applies to all Registrants except AEPTCo)

The Registrants engage in power, capacity and, to a lesser extent, natural gas marketing as major power producers and participants in electricity and natural gas markets. The Registrants also engage in power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity risk management activities focused on markets where the AEP System owns assets and adjacent markets. These activities include the purchase-and-sale of energy under forward contracts at fixed and variable prices. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, OTC swaps and options. Certain energy marketing and risk management transactions are with RTOs.

The Registrants recognize revenues from marketing and risk management transactions that are not derivatives as the performance obligation of delivering the commodity is satisfied. Expenses from marketing and risk management transactions that are not derivatives are also recognized upon delivery of the commodity.

The Registrants use MTM accounting for marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or elected normal under the normal purchase normal sale election. The Registrants include realized gains and losses on marketing and risk management transactions in revenues or expense based on the transaction's facts and circumstances. In certain jurisdictions subject to cost-based regulation, unrealized MTM amounts and some realized gains and losses are deferred as regulatory assets (for losses) and regulatory liabilities (for gains). Unrealized MTM gains and losses are included on the balance sheets as Risk Management Assets or Liabilities as appropriate.

Certain qualifying marketing and risk management derivatives transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). In the event the Registrants designate a cash flow hedge, cash flow hedge's gain or loss is initially recorded as a component of AOCI. When the forecasted transaction is realized and affects net income, the Registrants subsequently reclassify the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on their statements of income. See "Accounting for Cash Flow Hedging Strategies" section of Note 10.

Levelization of Nuclear Refueling Outage Costs (Applies to AEP and I&M)

In accordance with regulatory orders, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over approximately 18 months, beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins.

Maintenance

The Registrants expense maintenance costs as incurred. If it becomes probable that the Registrants will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. In certain regulated jurisdictions, the Registrants defer costs above the level included in base rates and amortize those deferrals commensurate with recovery through rate riders.

Income Taxes and Investment Tax Credits

The Registrants use the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled. The Registrants revalued deferred tax assets and liabilities at the new federal corporate income tax rate of 21% in December 2017. See Note 12 - Income Taxes for additional information related to Tax Reform.

When the flow-through method of accounting for temporary differences is required by a regulator to be reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

AEP and subsidiaries apply the deferral methodology for the recognition of ITC. Deferred ITC is amortized to income tax expense over the life of the asset that generated the credit. Amortization of deferred ITC begins when the asset is placed into service, except where regulatory commissions reflect ITC in the rate-making process, then amortization begins when the cash tax benefit is recognized.

The Registrants account for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." The Registrants classify interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classify penalties as Other Operation expense.

Excise Taxes (Applies to all Registrants except AEPTCo)

As agents for some state and local governments, the Registrants collect from customers certain excise taxes levied by those state or local governments on customers. The Registrants do not record these taxes as revenue or expense.

Debt

Gains and losses from the reacquisition of debt used to finance regulated electric utility plants are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Operations not subject to cost-based rate regulation report gains and losses on the reacquisition of debt in Interest Expense on the statements of income upon reacquisition.

Debt discount or premium and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. The net amortization expense is included in Interest Expense on the statements of income.

Goodwill (Applies to AEP)

When AEP acquires businesses, management records the fair value of all assets and liabilities. To the extent that consideration exceeds the fair value of identified assets, goodwill is recorded. Goodwill is not amortized. Management tests acquired goodwill at the reporting unit level for impairment at least annually at their estimated fair value. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, management estimates fair value using various internal and external valuation methods.

Pension and OPEB Plans (Applies to all Registrants except AEPTCo)

AEP sponsors a qualified pension plan and two unfunded nonqualified pension plans. Substantially all AEP employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. AEP also sponsors OPEB plans to provide health and life insurance benefits for retired employees. The Registrant Subsidiaries account for their participation in the AEP sponsored pension and OPEB plans using multiple-employer accounting. See Note 8 - Benefit Plans for additional information including significant accounting policies associated with the plans.

Investments Held in Trust for Future Liabilities (Applies to all Registrants except AEPTCo)

AEP has several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits, nuclear decommissioning and SNF disposal. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The investment strategy for the trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the investment risk of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. Management regularly reviews the actual asset allocations and periodically rebalances the investments to targeted allocations when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for AEP's benefit plans support the allocation of assets to minimize risks and optimize net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The objective of the investment policy for the pension fund is to maintain the funded status of the plan while providing for growth in the plan assets to offset the growth in the plan liabilities. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	25%
Fixed Income	59%
Other Investments	15%
Cash and Cash Equivalents	1%
OPEB Plans Assets	**Target**
Equity	49%
Fixed Income	49%
Cash and Cash Equivalents	2%

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities and prohibit the purchase of securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, the investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law.

For equity investments, the concentration limits are as follows:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- No individual stock may be more than 10% and 7% for pension and OPEB investments, respectively, of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, each investment manager's portfolio is compared to investment grade, diversified long and intermediate benchmark indices.

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added and opportunistic classifications and some investments in Real Estate Investment Trusts, which are publicly traded real estate securities.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value and not actively traded. The pension plan uses limited partnerships and commingled funds to invest across the private equity investment spectrum. The private equity holdings are with multiple general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout and hybrid debt and equity investment instruments.

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the collateral is invested. The difference between the rebate owed to the borrower and the collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is to provide modest incremental income with a limited increase in risk. As of December 31, 2018 and 2017, the fair value of securities on loan as part of the program was $241 million and $492 million, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2018 and 2017.

Trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company is held in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable Voluntary Employees' Beneficiary Association trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Nuclear Trust Funds (Applies to AEP and I&M)

Nuclear decommissioning and SNF trust funds represent funds that regulatory commissions allow I&M to collect through rates to fund future decommissioning and SNF disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP, I&M or their affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

I&M maintains trust funds for each regulatory jurisdiction. Regulatory approval is required to withdraw decommissioning funds. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

I&M records securities held in these trust funds in Spent Nuclear Fuel and Decommissioning Trusts on its balance sheets. I&M records these securities at fair value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. With the adoption of ASU 2016-01, effective January 2018, available for sale

classification only applies to investment in debt securities. Additionally, the adoption of ASU 2016-01 required changes in fair value of equity securities to be recognized in earnings. However, due to the regulatory treatment described below, this is not applicable for I&M's trust fund securities.

Other-than-temporary impairments for investments in debt securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the debt and equity investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. I&M records unrealized gains, unrealized losses and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. See the "Nuclear Contingencies" section of Note 6 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and Spent Nuclear Fuel Disposal" section of Note 11 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss) (Applies to all Registrants except AEPTCo)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Stock-Based Compensation Plans

As of December 31, 2018, AEP had performance units and restricted stock units outstanding under the American Electric Power System 2015 Long-Term Incentive Plan (2015 LTIP). Upon vesting, performance units awarded prior to 2017 are settled in cash and restricted stock units are settled in AEP common shares, except for restricted stock units granted after January 1, 2013 and prior to January 1, 2017 that vest to executive officers, which are settled in cash. All performance units and restricted stock units awarded after January 1, 2017 will be settled in AEP common shares. The impact of AEP's stock-based compensation plans are insignificant to the financial statements of the Registrant Subsidiaries.

AEP maintains a variety of tax qualified and nonqualified deferred compensation plans for employees and non-employee directors that include, among other options, an investment in or an investment return equivalent to that of AEP common stock. This includes AEP career shares maintained under the American Electric Power System Stock Ownership Requirement Plan (SORP), which facilitates executives in meeting minimum stock ownership requirements assigned to them by the Human Resources Committee of the Board of Directors. AEP career shares are derived from vested performance units granted to employees under the 2015 LTIP. AEP career shares accrue additional dividend shares in an amount equal to dividends paid on AEP common shares at the closing market price on the dividend payments date. All AEP career shares are paid out in AEP common stock after the executive's service with AEP ends.

Performance units awarded after January 1, 2017 are classified as temporary equity in the Mezzanine Equity section of the balance sheets. These awards may be settled in cash upon an employee's qualifying termination due to a change in control. Because such event is not solely within the control of the company, these awards are classified outside of permanent equity.

AEP compensates their non-employee directors, in part, with stock units under the American Electric Power Company, Inc. Stock Unit Accumulation Plan for Non-Employee Directors. These stock units become payable in cash to directors after their service ends.

Management measures and recognizes compensation expense for all share-based payment awards to employees and directors based on estimated fair values. For share-based payment awards with service only vesting conditions, management recognizes compensation expense on a straight-line basis. Stock-based compensation expense recognized on the statements of income for the years ended December 31, 2018, 2017 and 2016 is based on the number of outstanding awards at the end of each period without a reduction for estimated forfeitures. AEP accounts for forfeitures in the period in which they occur.

For the years ended December 31, 2018, 2017 and 2016, compensation cost is included in Net Income for the performance units, career shares, restricted stock units and the non-employee director's stock units. Compensation cost may also be capitalized. See Note 15 - Stock-based Compensation for additional information.

Equity Investment in Unconsolidated Affiliates (Applies to AEP and SWEPCo)

AEP and SWEPCo include equity in earnings from equity method investments in Equity Earnings (Loss) of Unconsolidated Subsidiaries on the statements of income. AEP and SWEPCo regularly monitor and evaluate equity method investments to determine whether they are impaired. An impairment is recorded when the investment has experienced a decline in value that is other-than-temporary in nature.

AEP has two significant equity method investments, ETT and DHLC. ETT designs, acquires, constructs, owns and operates certain transmission facilities in ERCOT. Berkshire Hathaway Energy, a nonaffiliated entity, holds a 50% membership interest in ETT, AEP Transmission Holdco holds a 49.5% membership interest in ETT and AEP Transmission Partner holds the remaining 0.5% membership interest in ETT. As a result, AEP, through its wholly-owned subsidiaries, holds a 50% membership interest in ETT. As of December 31, 2018 and 2017, AEP's investment in ETT was $666 million and $664 million, respectively, which is included in Deferred Charges and Other Noncurrent Assets on the balance sheets. AEP's equity earnings associated with ETT were $62 million and $82 million for the years ended December 31, 2018 and 2017. See "Non-Consolidated Significant Variable Interest" section of Note 17 for more information about DHLC.

Earnings Per Share (EPS) (Applies to AEP)

Basic EPS is calculated by dividing net earnings available to common shareholders by the weighted-average number of common shares outstanding during the period. Diluted EPS is calculated by adjusting the weighted-average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards.

The following table presents AEP's basic and diluted EPS calculations included on the statements of income:

	Years Ended December 31,					
	2018		2017		2016	
	(in millions, except per share data)					
		$/share		$/share		$/share
Income from Continuing Operations	$ 1,931.3		$ 1,928.9		$ 620.5	
Less: Net Income Attributable to Noncontrolling Interests	7.5		16.3		7.1	
Earnings Attributable to AEP Common Shareholders from Continuing Operations	$ 1,923.8		$ 1,912.6		$ 613.4	
Weighted Average Number of Basic Shares Outstanding	492.8	$ 3.90	491.8	$ 3.89	491.5	$ 1.25
Weighted Average Dilutive Effect of Stock-Based Awards	1.0	—	0.8	(0.01)	0.2	—
Weighted Average Number of Diluted Shares Outstanding	493.8	$ 3.90	492.6	$ 3.88	491.7	$ 1.25

There were no antidilutive shares outstanding as of December 31, 2018, 2017 and 2016.

Supplementary Income Statement Information

The following tables provide the components of Depreciation and Amortization for the years ended December 31, 2018, 2017 and 2016:

2018

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 1,965.0	$ 262.2	$ 133.9	$ 428.1	$ 278.9	$ 232.6	$ 155.5	$ 237.0
Amortization of Certain Securitized Assets	287.9	240.0	—	—	—	47.9	—	—
Amortization of Regulatory Assets and Liabilities	33.7	(2.6)	—	0.3	14.2	(20.8)	8.5	2.5
Total Depreciation and Amortization	$ 2,286.6	$ 499.6	$ 133.9	$ 428.4	$ 293.1	$ 259.7	$ 164.0	$ 239.5

2017

Depreciation and Amortization	AEP	AEP Texas	AEPTCo (a)	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 1,709.1	$ 221.1	$ 95.7	$ 407.6	$ 203.1	$ 200.9	$ 131.4	$ 217.2
Amortization of Certain Securitized Assets	275.9	231.4	—	—	—	44.4	—	—
Amortization of Regulatory Assets and Liabilities	12.2	(2.4)	—	0.3	7.8	(19.4)	(1.0)	0.2
Total Depreciation and Amortization	$ 1,997.2	$ 450.1	$ 95.7	$ 407.9	$ 210.9	$ 225.9	$ 130.4	$ 217.4

2016

Depreciation and Amortization	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Depreciation and Amortization of Property, Plant and Equipment	$ 1,688.5	$ 204.0	$ 65.9	$ 387.6	$ 183.9	$ 202.3	$ 122.6	$ 196.6
Amortization of Certain Securitized Assets	254.6	210.3	—	—	—	44.3	—	—
Amortization of Regulatory Assets and Liabilities	19.2	(0.4)	—	0.9	7.8	(8.0)	7.6	(0.1)
Total Depreciation and Amortization	$ 1,962.3	$ 413.9	$ 65.9	$ 388.5	$ 191.7	$ 238.6	$ 130.2	$ 196.5

(a) Reflects the revisions made to AEPTCo's previously issued financial statements. For additional details on the revisions to AEPTCo's financial statements, see "Revisions to Previously Issued Financial Statements" below.

Supplementary Cash Flow Information (Applies to AEP)

Cash Flow Information	Years Ended December 31, 2018	2017	2016
		(in millions)	
Cash Paid (Received) for:			
Interest, Net of Capitalized Amounts	$ 939.3	$ 858.3	$ 848.5
Income Taxes	(24.7)	(1.1)	29.5
Noncash Investing and Financing Activities:			
Acquisitions Under Capital Leases	55.6	60.7	86.1
Construction Expenditures Included in Current Liabilities as of December 31,	1,120.4	1,330.8	858.0
Construction Expenditures Included in Noncurrent Liabilities as of December 31,	—	71.8	—
Acquisition of Nuclear Fuel Included in Current Liabilities as of December 31,	4.0	—	2.1
Noncash Contribution of Assets by Noncontrolling Interest	84.0	—	—
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	2.2	2.6	0.7

Revisions to Previously Issued Financial Statements (Applies to AEPTCo)

In the second quarter of 2018, management identified certain transmission assets that it believes should not have been included in AEPTCo's SPP transmission formula rates. As a result, AEPTCo recorded a pretax out of period correction of an error of approximately $17 million related to revenue recorded from 2013 through March 31, 2018 in the second quarter of 2018. Subsequent to filing the second quarter 2018 Form 10-Q, AEPTCo identified an additional error in its previously issued financial statements. This error resulted from the improper capitalization of AFUDC and subsequent revenue recorded on the AFUDC. The impact of this misstatement reduced AEPTCo's pretax income by approximately $7 million on a cumulative basis for the period 2011 through June 30, 2018.

Management assessed the materiality of the misstatements on all previously issued AEPTCo financial statements in accordance with SEC Staff Accounting Bulletin (SAB) No. 99, Materiality, codified in ASC 250, Presentation of Financial Statements and concluded these misstatements were not material, individually or in the aggregate, to any prior annual or interim period. In accordance with ASC 250 (SAB No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements), management revised the prior period AEPTCo financial statements included in this report to reflect the impact of correcting the immaterial misstatements described above. In addition, management will revise the March 31, 2018 and June 30, 2018 periods presented in AEPTCo's previously issued financial statements in future SEC Form 10-Q filings to reflect the impact of the misstatements. The $(20) million adjustment to pretax income for the year ended December 31, 2017 includes adjustments of $(12) million relating to 2016 and earlier periods. The effect of recording this adjustment of $(12) million in 2017 is not material to AEPTCo's financial statements for 2017 or any earlier period.

AEPTCo has also corrected other previously recorded immaterial out of period adjustments. The impact of these additional adjustments did not impact net income in any period.

Management also assessed the materiality of AEPTCo's misstatements discussed above on all previously issued and current year AEP financial statements in accordance with ASC 250, and concluded these misstatements were not material, individually or in the aggregate, to any prior and current interim and annual period financial statements. As a result, AEP recorded the correction in the third quarter of 2018.

Statement of Income

The table below reflects the effects of correcting the immaterial errors described above on AEPTCo's statement of income for the twelve months ended December 31, 2017:

	Twelve Months Ended December 31, 2017		
	As Reported	Adjustments	As Adjusted
		(in millions)	
TOTAL REVENUES	$ 723.2	$ (16.3)	$ 706.9
EXPENSES			
Depreciation and Amortization	97.1	(1.4)	95.7
TOTAL EXPENSES	275.4	(1.4)	274.0
OPERATING INCOME	447.8	(14.9)	432.9
Other Income (Expense):			
Allowance for Equity Funds Used During Construction	52.3	(3.3)	49.0
Interest Expense	(68.0)	(2.2)	(70.2)
INCOME BEFORE INCOME TAX EXPENSE	433.3	(20.4)	412.9
Income Tax Expense	147.2	(5.0)	142.2
NET INCOME	$ 286.1	$ (15.4)	$ 270.7

Balance Sheet

The table below reflects the effects of correcting the immaterial errors described above on AEPTCo's Balance Sheet as of December 31, 2017:

	December 31, 2017		
	As Reported	Adjustment	As Adjusted
CURRENT ASSETS		(in millions)	
Accounts Receivable:			
Customers	$ 19.1	$ (4.1)	$ 15.0
Total Accounts Receivable	113.6	(4.1)	109.5
Accrued Tax Benefits	46.6	2.8	49.4
TOTAL CURRENT ASSETS	327.7	(1.3)	326.4
TRANSMISSION PROPERTY			
Transmission Property	5,336.1	(16.4)	5,319.7
Other Property, Plant and Equipment	131.4	(4.6)	126.8
Construction Work in Progress	1,312.7	11.3	1,324.0
Total Transmission Property	6,780.2	(9.7)	6,770.5
Accumulated Depreciation and Amortization	170.4	(17.8)	152.6
TOTAL TRANSMISSION PROPERTY – NET	6,609.8	8.1	6,617.9
OTHER NONCURRENT ASSETS			
Deferred Property Taxes	117.8	7.2	125.0
TOTAL OTHER NONCURRENT ASSETS	130.6	7.2	137.8
TOTAL ASSETS	$ 7,068.1	$ 14.0	$ 7,082.1
CURRENT LIABILITIES			
Accounts Payable:			
General	$ 473.2	$ 11.3	$ 484.5
Affiliated Companies	52.9	13.2	66.1
Accrued Taxes	225.4	6.1	231.5
TOTAL CURRENT LIABILITIES	836.3	30.6	866.9
NONCURRENT LIABILITIES			
Deferred Income Taxes	601.7	(1.3)	600.4
Regulatory Liabilities	493.7	0.1	493.8
TOTAL NONCURRENT LIABILITIES	3,626.5	(1.2)	3,625.3
TOTAL LIABILITIES	4,462.8	29.4	4,492.2
MEMBER'S EQUITY			
Retained Earnings	788.7	(15.4)	773.3
TOTAL MEMBER'S EQUITY	2,605.3	(15.4)	2,589.9
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 7,068.1	$ 14.0	$ 7,082.1

Statement of Cash Flows

The table below reflects the effects of correcting the immaterial errors described above on AEPTCo's statement of cash flows for the twelve months ended December 31, 2017:

	Twelve Months Ended December 31, 2017		
	As Reported	**Adjustments**	**As Adjusted**
		(in millions)	
OPERATING ACTIVITIES			
Net Income	$ 286.1	$ (15.4)	$ 270.7
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	97.1	(1.4)	95.7
Deferred Income Taxes	272.8	(1.3)	271.5
Allowance for Equity Funds Used During Construction	(52.3)	3.3	(49.0)
Property Taxes	(15.6)	(7.2)	(22.8)
Change in Other Noncurrent Assets	9.8	1.2	11.0
Change in Other Noncurrent Liabilities	27.3	0.2	27.5
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(34.5)	4.1	(30.4)
Accounts Payable	9.8	13.2	23.0
Accrued Taxes, Net	13.0	3.3	16.3
Net Cash Flows from Operating Activities	604.8	—	604.8
INVESTING ACTIVITIES			
Net Cash Flows Used for Investing Activities	(1,595.6)	—	(1,595.6)
FINANCING ACTIVITIES			
Net Cash Flows from Financing Activities	990.8	—	990.8
Net Change in Cash and Cash Equivalents	—	—	—
Cash and Cash Equivalents at Beginning of Period	—	—	—
Cash and Cash Equivalents at End of Period	$ —	$ —	$ —
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 61.2	$ 1.2	$ 62.4
Construction Expenditures Included in Current Liabilities as of December 31,	473.7	11.3	485.0

Statement of Changes in Member's Equity

The statement of changes in AEPTCo's member's equity reflects the adjustments to Net Income of $(15) million for the twelve months ended December 31, 2017 as shown in the table under Net Income above. The statement of changes in member's equity also reflects the adjustments to Retained Earnings of $(15) million as of December 31, 2017 as shown in the table under Balance Sheet above.

2. NEW ACCOUNTING PRONOUNCEMENTS

The disclosures in this note apply to all Registrants unless indicated otherwise.

During FASB's standard-setting process and upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to the Registrants' business. The following pronouncements will impact the financial statements.

ASU 2014-09 "Revenue from Contracts with Customers" (ASU 2014-09)

In May 2014, the FASB issued ASU 2014-09 changing the method used to determine the timing and requirements for revenue recognition on the statements of income. Under the new standard, an entity must identify the performance obligations in a contract with a customer, determine the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. The amendments in this update also require disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

Management adopted ASU 2014-09 effective January 1, 2018, by means of the modified retrospective approach for all contracts within the scope of the new standard. The adoption of ASU 2014-09 did not have a material impact on results of operations, financial position or cash flows. In that regard, the application of the new standard did not cause any significant differences in any individual financial statement line items had those line items been presented in accordance with the guidance that was in effect prior to the adoption of the new standard. Further, given the lack of material impact to the financial statements, the adoption of the new standard did not give rise to any material changes in the Registrants' previously established accounting policies for revenue. See Note 20 - Revenue from Contracts with Customers for additional disclosures required by the new standard.

ASU 2016-01 "Recognition and Measurement of Financial Assets and Financial Liabilities" (ASU 2016-01)

In January 2016, the FASB issued ASU 2016-01 revising the reporting model for financial instruments. Under the new standard, equity investments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) are required to be measured at fair value with changes in fair value recognized in net income. For equity investments that do not have a readily determinable fair value, entities are permitted to elect a practicality exception and measure the investment at cost, less impairment, plus or minus observable price changes. The new standard also amends disclosure requirements and requires separate presentation of financial assets and liabilities by measurement category and form of financial asset (that is, securities or loans and receivables) on the balance sheets or the accompanying notes to the financial statements. The amendments also clarify that an entity should evaluate the need for a valuation allowance on a deferred tax asset related to available-for-sale securities in combination with the entity's other deferred tax assets.

Management adopted ASU 2016-01 effective January 1, 2018, by means of a cumulative-effect adjustment to the balance sheet. The adoption of ASU 2016-01 resulted in an immaterial impact to the results of operations and financial position of AEP, and no impact to the results of operations or financial position of the Registrant Subsidiaries. There was no impact on cash flows of the Registrants.

ASU 2016-02 "Accounting for Leases" (ASU 2016-02)

In February 2016, the FASB issued ASU 2016-02 increasing the transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheets and disclosing key information about leasing arrangements. Under the new standard, an entity must recognize an asset and liability for operating leases on the balance sheets. Additionally, a capital lease will be known as a finance lease going forward. Leases with terms of 12 months or longer will be subject to the new requirements. Fundamentally, the criteria used to determine lease classification will remain the same, but will be more subjective under the new standard.

New leasing standard implementation activities included the identification of the lease population within the AEP System as well as the sampling of representative lease contracts to analyze accounting treatment under the new accounting guidance. Based upon the completed assessments, management also prepared a gap analysis to outline new disclosure compliance requirements.

Management adopted ASU 2016-02 effective January 1, 2019 by means of a cumulative-effect adjustment to the balance sheet. Management elected the following practical expedients upon adoption:

Practical Expedient	Description
Overall Expedients (for leases commenced prior to adoption date and must be adopted as a package)	Do not need to reassess whether any expired or existing contracts are/or contain leases, do not need to reassess the lease classification for any expired or existing leases and do not need to reassess initial direct costs for any existing leases.
Lease and Non-lease Components (elect by class of underlying asset)	Elect as an accounting policy to not separate non-lease components from lease components and instead account for each lease and associated non-lease component as a single lease component.
Short-term Lease (elect by class of underlying asset)	Elect as an accounting policy to not apply the recognition requirements to short-term leases.
Existing and expired land easements not previously accounted for as leases	Elect optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the current leases guidance in Topic 840.
Cumulative-effect adjustment in the period of adoption	Elect the optional transition practical expedient to adopt the new lease requirements through a cumulative-effect adjustment on the balance sheet in the period of adoption.

Management concluded that the result of adoption would not materially change the volume of contracts that qualify as leases going forward. The adoption of the new standard did not materially impact results of operations or cash flows, but did have a material impact on the balance sheet. The impact to the balance sheet has been estimated for the first quarter of 2019 as shown in the table below.

Company	Estimated Obligation
	(in millions)
AEP	$ 1,070.4
AEP Texas	80.2
AEPTCo	5.4
APCo	80.4
I&M	351.1
OPCo	76.8
PSO	32.2
SWEPCo	35.8

ASU 2016-13 "Measurement of Credit Losses on Financial Instruments" (ASU 2016-13)

In June 2016, the FASB issued ASU 2016-13 requiring an allowance to be recorded for all expected credit losses for financial assets. The allowance for credit losses is based on historical information, current conditions and reasonable and supportable forecasts. The new standard also makes revisions to the other than temporary impairment model for available-for-sale debt securities. Disclosures of credit quality indicators in relation to the amortized cost of financing receivables are further disaggregated by year of origination.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2019, with early adoption permitted for interim and annual periods beginning after December 15, 2018. The amendments will be applied through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. Management is analyzing the impact of this new standard and, at this time, cannot estimate the impact of adoption on net income. Management plans to adopt ASU 2016-13 and related implementation guidance effective January 1, 2020.

ASU 2017-07 "Compensation - Retirement Benefits" (ASU 2017-07)

In March 2017, the FASB issued ASU 2017-07 requiring that an employer report the service cost component of pension and postretirement benefits in the same line item or items as other compensation costs. The other components of net benefit cost are required to be presented on the statements of income separately from the service cost component and outside of a subtotal of income from operations. In addition, only the service cost component is eligible for capitalization as applicable following labor.

Management adopted ASU 2017-07 effective January 1, 2018. Presentation of the non-service components on a separate line outside of operating income was applied on a retrospective basis, using the amounts disclosed in the benefit plan note for the estimation basis as a practical expedient. Capitalization of only the service cost component was applied on a prospective basis.

ASU 2017-12 "Derivatives and Hedging" (ASU 2017-12)

In August 2017, the FASB issued ASU 2017-12 amending the recognition and presentation requirements for hedge accounting activities. The objectives of the new standard are to improve the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements and to reduce the complexity of applying hedge accounting. Among other things, ASU 2017-12: (a) expands the types of transactions eligible for hedge accounting, (b) eliminates the separate measurement and presentation of hedge ineffectiveness, (c) simplifies the requirements for assessments of hedge effectiveness, (d) provides companies more time to finalize hedge documentation and (e) enhances presentation and disclosure requirements.

Management early adopted ASU 2017-12 in the second quarter of 2018, effective January 1, 2018, by means of a modified retrospective approach. The adoption of ASU 2017-12 resulted in an immaterial impact to the results of operations and financial position of AEP, and no impact to results of operations or financial position of the Registrant Subsidiaries. There was no impact on cash flows of the Registrants. The adoption of the new standard did not give rise to any material changes to the Registrants' previously established accounting policies for derivatives and hedging.

ASU 2018-02 "Reclassification of Certain Tax Effects from AOCI" (ASU 2018-02)

In February 2018, the FASB issued ASU 2018-02 allowing a reclassification from AOCI to Retained Earnings for stranded tax effects resulting from Tax Reform. The accounting guidance for "Income Taxes" requires deferred tax assets and liabilities to be adjusted for the effect of a change in tax law or rates with the effect included in income from continuing operations in the reporting period that includes the enactment date of the tax change. This guidance is applicable for the tax effects of items in AOCI that were originally recognized in Other Comprehensive Income. As a result and absent the new guidance in this ASU, the tax effects of items within AOCI would not reflect the newly enacted corporate tax rate.

Management adopted ASU 2018-02 effective January 1, 2018, electing to reclassify the effects of the change in the federal corporate tax rate due to Tax Reform from AOCI to Retained Earnings. A portion of the reclassification was recorded to Regulatory Liabilities to adjust the tax effects of certain interest rate hedges in AEP's regulated jurisdictions that were previously deferred as a part of the accounting for Tax Reform. There were no other effects from Tax Reform that impacted AOCI. Management applied the new guidance at the beginning of the period of adoption. The adoption of the new standard did not have a material impact on the statement of financial position and did not impact results of operations or cash flows.

ASU 2018-14 "Disclosure Framework: Changes to the Disclosure Requirements for Defined Benefit Plans" (ASU 2018-14)

In August 2018, the FASB issued ASU 2018-14 modifying the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. The amendments in this Update to Subtopic 715-20 remove disclosures that no longer are considered cost beneficial, clarify the specific requirements of disclosures and add disclosure requirements identified as relevant.

Management early adopted ASU 2018-14 for the 2018 Annual Report and applied the new standard retrospectively for all periods presented. As a result of adoption, the Registrants' disclosures were updated as follows:

- Amended the disclosure to remove the amounts in AOCI expected to be recognized as components of net periodic benefit cost over the next fiscal year.
- Amended the disclosure to remove the effects of a one-percentage-point change in assumed health care cost trend rates on the (a) aggregate of the service and interest cost components of net periodic benefit costs and (b) benefit obligation for postretirement health care benefits.
- Amended the disclosure to include the weighted-average interest crediting rates for cash balance plans and other plans with promised interest crediting rates.
- Amended the disclosure to include an explanation of the reasons for significant gains and losses related to changes in the benefit obligation for the period.

See Note 8 - Benefit Plans for updates to the disclosures required by the new standard.

ASU 2018-15 "Internal-Use Software: Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract" (ASU 2018-15)

In August 2018, the FASB issued ASU 2018-15 aligning the requirements for capitalizing implementation costs incurred in a cloud computing arrangement (hosting arrangement) that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. The new standard requires an entity (customer) in a hosting arrangement that is a service contract to follow the accounting guidance for "Internal-Use Software" to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. To eliminate diversity in practice, the new standard changes the presentation of implementation costs for cloud service arrangements that are service contracts without the purchase of a license. Implementation costs for cloud service contracts will be presented on the balance sheets in the same manner as a prepayment. The Registrants currently present implementation costs in property, plant and equipment on the balance sheets. Under the new standard, amortization of capitalized implementation costs of a hosting arrangement will be recorded in Operation and Maintenance expense over the term of the cloud service arrangement, rather than Depreciation and Amortization expense on the statements of income. Payments for capitalized implementation costs in the statement of cash flows will be classified in the same manner as payments made for fees associated with the hosting element.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2019, with early adoption permitted. The amendments may be applied either retrospectively or prospectively to applicable implementation costs incurred after the date of adoption. Management is analyzing the impact of this new standard and at this time, cannot estimate the impact of adoption on results of operations, financial position or cash flows. Management plans to adopt ASU 2018-15 prospectively, effective January 1, 2020.

3. COMPREHENSIVE INCOME

The disclosures in this note apply to all Registrants except for AEPTCo. AEPTCo does not have any components of other comprehensive income for any period presented in the financial statements.

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI for the years ended December 31, 2018, 2017 and 2016. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 8 - Benefit Plans for additional details.

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2018

	Cash Flow Hedges			Pension and OPEB		
	Commodity	Interest Rate	Securities Available for Sale	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)			
Balance in AOCI as of December 31, 2017	$ (28.4)	$ (13.0)	$ 11.9	$ 141.6	$ (179.9)	$ (67.8)
Change in Fair Value Recognized in AOCI	37.3	2.3	—	—	(33.0)	6.6
Amount of (Gain) Loss Reclassified from AOCI						
Generation & Marketing Revenues (a)	(0.1)	—	—	—	—	(0.1)
Purchased Electricity for Resale (a)	(32.6)	—	—	—	—	(32.6)
Interest Expense (a)	—	1.1	—	—	—	1.1
Amortization of Prior Service Cost (Credit)	—	—	—	(19.5)	—	(19.5)
Amortization of Actuarial (Gains) Losses	—	—	—	12.8	—	12.8
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(32.7)	1.1	—	(6.7)	—	(38.3)
Income Tax (Expense) Benefit	(6.9)	0.3	—	(1.4)	—	(8.0)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(25.8)	0.8	—	(5.3)	—	(30.3)
Net Current Period Other Comprehensive Income (Loss)	11.5	3.1	—	(5.3)	(33.0)	(23.7)
ASU 2018-02 Adoption (b)	(6.1)	(2.7)	—	—	(8.2)	(17.0)
ASU 2016-01 Adoption (b)	—	—	(11.9)	—	—	(11.9)
Balance in AOCI as of December 31, 2018	$ (23.0)	$ (12.6)	$ —	$ 136.3	$ (221.1)	$ (120.4)

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2017

	Cash Flow Hedges			Pension and OPEB		
	Commodity	Interest Rate	Securities Available for Sale	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)			
Balance in AOCI as of December 31, 2016	$ (23.1)	$ (15.7)	$ 8.4	$ 140.5	$ (266.4)	$ (156.3)
Change in Fair Value Recognized in AOCI	(20.4)	1.6	3.5	—	86.5	71.2
Amount of (Gain) Loss Reclassified from AOCI						
Generation & Marketing Revenues (a)	(5.6)	—	—	—	—	(5.6)
Purchased Electricity for Resale (a)	28.8	—	—	—	—	28.8
Interest Expense (a)	—	1.5	—	—	—	1.5
Amortization of Prior Service Cost (Credit)	—	—	—	(19.6)	—	(19.6)
Amortization of Actuarial (Gains) Losses	—	—	—	21.3	—	21.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	23.2	1.5	—	1.7	—	26.4
Income Tax (Expense) Benefit	8.1	0.4	—	0.6	—	9.1
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	15.1	1.1	—	1.1	—	17.3
Net Current Period Other Comprehensive Income (Loss)	(5.3)	2.7	3.5	1.1	86.5	88.5
Balance in AOCI as of December 31, 2017	$ (28.4)	$ (13.0)	$ 11.9	$ 141.6	$ (179.9)	$ (67.8)

AEP

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Cash Flow Hedges			Pension and OPEB		
	Commodity	Interest Rate	Securities Available for Sale	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)			
Balance in AOCI as of December 31, 2015	$ (5.2)	$ (17.2)	$ 7.1	$ 139.9	$ (251.7)	$ (127.1)
Change in Fair Value Recognized in AOCI	(14.6)	—	1.3	—	(14.7)	(28.0)
Amount of (Gain) Loss Reclassified from AOCI						
Generation & Marketing Revenues (a)	(21.4)	—	—	—	—	(21.4)
Purchased Electricity for Resale (a)	16.4	—	—	—	—	16.4
Interest Expense (a)	—	2.4	—	—	—	2.4
Amortization of Prior Service Cost (Credit)	—	—	—	(19.4)	—	(19.4)
Amortization of Actuarial (Gains) Losses	—	—	—	20.3	—	20.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(5.0)	2.4	—	0.9	—	(1.7)
Income Tax (Expense) Benefit	(1.7)	0.9	—	0.3	—	(0.5)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(3.3)	1.5	—	0.6	—	(1.2)
Net Current Period Other Comprehensive Income (Loss)	(17.9)	1.5	1.3	0.6	(14.7)	(29.2)
Balance in AOCI as of December 31, 2016	$ (23.1)	$ (15.7)	$ 8.4	$ 140.5	$ (266.4)	$ (156.3)

AEP Texas

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2018

		Pension and OPEB		
	Cash Flow Hedge – Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2017	$ (4.5)	$ 4.5	$ (12.6)	$ (12.6)
Change in Fair Value Recognized in AOCI	—	—	(1.0)	(1.0)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (a)	1.3	—	—	1.3
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.4	—	0.4
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.3	0.3	—	1.6
Income Tax (Expense) Benefit	0.3	0.1	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.0	0.2	—	1.2
Net Current Period Other Comprehensive Income (Loss)	1.0	0.2	(1.0)	0.2
ASU 2018-02 Adoption (b)	(0.9)	—	(1.8)	(2.7)
Balance in AOCI as of December 31, 2018	$ (4.4)	$ 4.7	$ (15.4)	$ (15.1)

AEP Texas

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2017

		Pension and OPEB		
	Cash Flow Hedge – Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2016	$ (5.4)	$ 4.2	$ (13.7)	$ (14.9)
Change in Fair Value Recognized in AOCI	—	—	1.1	1.1
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (a)	1.3	—	—	1.3
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.5	—	0.5
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.3	0.4	—	1.7
Income Tax (Expense) Benefit	0.4	0.1	—	0.5
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.9	0.3	—	1.2
Net Current Period Other Comprehensive Income (Loss)	0.9	0.3	1.1	2.3
Balance in AOCI as of December 31, 2017	$ (4.5)	$ 4.5	$ (12.6)	$ (12.6)

AEP Texas

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

		Pension and OPEB		
	Cash Flow Hedge – Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2015	$ (6.5)	$ 3.9	$ (14.6)	$ (17.2)
Change in Fair Value Recognized in AOCI	(0.1)	—	0.9	0.8
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (a)	1.8	—	—	1.8
Amortization of Prior Service Cost (Credit)	—	(0.1)	—	(0.1)
Amortization of Actuarial (Gains) Losses	—	0.5	—	0.5
Reclassifications from AOCI, before Income Tax (Expense) Benefit	1.8	0.4	—	2.2
Income Tax (Expense) Benefit	0.6	0.1	—	0.7
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.2	0.3	—	1.5
Net Current Period Other Comprehensive Income (Loss)	1.1	0.3	0.9	2.3
Balance in AOCI as of December 31, 2016	$ (5.4)	$ 4.2	$ (13.7)	$ (14.9)

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2018

	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)		
Balance in AOCI as of December 31, 2017	$ —	$ 2.2	$ 14.8	$ (15.7)	$ 1.3
Change in Fair Value Recognized in AOCI	(0.7)	—	—	(2.6)	(3.3)
Amount of (Gain) Loss Reclassified from AOCI					
Purchased Electricity for Resale (a)	0.9	—	—	—	0.9
Interest Expense (a)	—	(1.1)	—	—	(1.1)
Amortization of Prior Service Cost (Credit)	—	—	(5.2)	—	(5.2)
Amortization of Actuarial (Gains) Losses	—	—	1.3	—	1.3
Reclassifications from AOCI, before Income Tax (Expense) Benefit	0.9	(1.1)	(3.9)	—	(4.1)
Income Tax (Expense) Benefit	0.2	(0.2)	(0.8)	—	(0.8)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	0.7	(0.9)	(3.1)	—	(3.3)
Net Current Period Other Comprehensive Income (Loss)	—	(0.9)	(3.1)	(2.6)	(6.6)
ASU 2018-02 Adoption (b)	—	0.5	—	(0.2)	0.3
Balance in AOCI as of December 31, 2018	$ —	$ 1.8	$ 11.7	$ (18.5)	$ (5.0)

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2017

		Pension and OPEB		
	Cash Flow Hedge – Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2016	$ 2.9	$ 16.0	$ (27.3)	$ (8.4)
Change in Fair Value Recognized in AOCI	—	—	11.6	11.6
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (a)	(1.1)	—	—	(1.1)
Amortization of Prior Service Cost (Credit)	—	(5.2)	—	(5.2)
Amortization of Actuarial (Gains) Losses	—	3.4	—	3.4
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.1)	(1.8)	—	(2.9)
Income Tax (Expense) Benefit	(0.4)	(0.6)	—	(1.0)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.7)	(1.2)	—	(1.9)
Net Current Period Other Comprehensive Income (Loss)	(0.7)	(1.2)	11.6	9.7
Balance in AOCI as of December 31, 2017	$ 2.2	$ 14.8	$ (15.7)	$ 1.3

APCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Cash Flow Hedge – Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2015	$ 3.6	$ 17.4	$ (23.8)	$ (2.8)
Change in Fair Value Recognized in AOCI	—	—	(3.5)	(3.5)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (a)	(1.1)	—	—	(1.1)
Amortization of Prior Service Cost (Credit)	—	(5.1)	—	(5.1)
Amortization of Actuarial (Gains) Losses	—	3.0	—	3.0
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.1)	(2.1)	—	(3.2)
Income Tax (Expense) Benefit	(0.4)	(0.7)	—	(1.1)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.7)	(1.4)	—	(2.1)
Net Current Period Other Comprehensive Income (Loss)	(0.7)	(1.4)	(3.5)	(5.6)
Balance in AOCI as of December 31, 2016	$ 2.9	$ 16.0	$ (27.3)	$ (8.4)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2018

	Cash Flow Hedge – Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2017	$ (10.7)	$ 5.1	$ (6.5)	$ (12.1)
Change in Fair Value Recognized in AOCI	—	—	(0.6)	(0.6)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (a)	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.8)	—	(0.8)
Amortization of Actuarial (Gains) Losses	—	0.8	—	0.8
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.0	—	—	2.0
Income Tax (Expense) Benefit	0.4	—	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.6	—	—	1.6
Net Current Period Other Comprehensive Income (Loss)	1.6	—	(0.6)	1.0
ASU 2018-02 Adoption (b)	(2.4)	—	(0.3)	(2.7)
Balance in AOCI as of December 31, 2018	$ (11.5)	$ 5.1	$ (7.4)	$ (13.8)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2017

	Cash Flow Hedge – Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2016	$ (12.0)	$ 5.1	$ (9.3)	$ (16.2)
Change in Fair Value Recognized in AOCI	—	—	2.8	2.8
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (a)	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.9)	—	(0.9)
Amortization of Actuarial (Gains) Losses	—	0.9	—	0.9
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.0	—	—	2.0

Income Tax (Expense) Benefit	0.7	—	—	0.7
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.3	—	—	1.3
Net Current Period Other Comprehensive Income (Loss)	1.3	—	2.8	4.1
Balance in AOCI as of December 31, 2017	$ (10.7)	$ 5.1	$ (6.5)	$ (12.1)

I&M

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Cash Flow Hedge – Interest Rate	Pension and OPEB: Amortization of Deferred Costs	Pension and OPEB: Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2015	$ (13.3)	$ 5.1	$ (8.5)	$ (16.7)
Change in Fair Value Recognized in AOCI	—	—	(0.8)	(0.8)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (a)	2.0	—	—	2.0
Amortization of Prior Service Cost (Credit)	—	(0.8)	—	(0.8)
Amortization of Actuarial (Gains) Losses	—	0.8	—	0.8
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.0	—	—	2.0
Income Tax (Expense) Benefit	0.7	—	—	0.7
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.3	—	—	1.3
Net Current Period Other Comprehensive Income (Loss)	1.3	—	(0.8)	0.5
Balance in AOCI as of December 31, 2016	$ (12.0)	$ 5.1	$ (9.3)	$ (16.2)

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2018

	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2017	$ 1.9
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(1.7)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.7)
Income Tax (Expense) Benefit	(0.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(1.3)
Net Current Period Other Comprehensive Income (Loss)	(1.3)
ASU 2018-02 Adoption (b)	0.4
Balance in AOCI as of December 31, 2018	$ 1.0

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2017

	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2016	$ 3.0
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(1.7)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.7)
Income Tax (Expense) Benefit	(0.6)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(1.1)
Net Current Period Other Comprehensive Income (Loss)	(1.1)
Balance in AOCI as of December 31, 2017	$ 1.9

OPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2015	$ 4.3
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(1.9)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.9)
Income Tax (Expense) Benefit	(0.6)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(1.3)
Net Current Period Other Comprehensive Income (Loss)	(1.3)
Balance in AOCI as of December 31, 2016	$ 3.0

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2018

	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2017	$ 2.6
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(1.3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.3)
Income Tax (Expense) Benefit	(0.3)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(1.0)
Net Current Period Other Comprehensive Income (Loss)	(1.0)
ASU 2018-02 Adoption (b)	0.5
Balance in AOCI as of December 31, 2018	$ 2.1

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2017

	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2016	$ 3.4
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(1.3)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.3)
Income Tax (Expense) Benefit	(0.5)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.8)
Net Current Period Other Comprehensive Income (Loss)	(0.8)
Balance in AOCI as of December 31, 2017	$ 2.6

PSO

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

	Cash Flow Hedge – Interest Rate
	(in millions)
Balance in AOCI as of December 31, 2015	$ 4.2
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Interest Expense (a)	(1.2)
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(1.2)
Income Tax (Expense) Benefit	(0.4)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(0.8)
Net Current Period Other Comprehensive Income (Loss)	(0.8)
Balance in AOCI as of December 31, 2016	$ 3.4

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2018

		Pension and OPEB		
	Cash Flow Hedge – Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2017	$ (6.0)	$ 1.2	$ 0.8	$ (4.0)
Change in Fair Value Recognized in AOCI	2.3	—	(3.1)	(0.8)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (a)	2.1	—	—	2.1
Amortization of Prior Service Cost (Credit)	—	(2.0)	—	(2.0)
Amortization of Actuarial (Gains) Losses	—	0.2	—	0.2
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.1	(1.8)	—	0.3
Income Tax (Expense) Benefit	0.4	(0.4)	—	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.7	(1.4)	—	0.3
Net Current Period Other Comprehensive Income (Loss)	4.0	(1.4)	(3.1)	(0.5)
ASU 2018-02 Adoption (b)	(1.3)	—	0.4	(0.9)
Balance in AOCI as of December 31, 2018	$ (3.3)	$ (0.2)	$ (1.9)	$ (5.4)

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2017

		Pension and OPEB		
	Cash Flow Hedge – Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2016	$ (7.4)	$ 1.9	$ (3.9)	$ (9.4)
Change in Fair Value Recognized in AOCI	—	—	4.7	4.7
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (a)	2.2	—	—	2.2
Amortization of Prior Service Cost (Credit)	—	(2.0)	—	(2.0)
Amortization of Actuarial (Gains) Losses	—	0.9	—	0.9
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.2	(1.1)	—	1.1
Income Tax (Expense) Benefit	0.8	(0.4)	—	0.4
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.4	(0.7)	—	0.7
Net Current Period Other Comprehensive Income (Loss)	1.4	(0.7)	4.7	5.4

Balance in AOCI as of December 31, 2017	$ (6.0)	$ 1.2	$ 0.8	$ (4.0)

SWEPCo

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2016

		Pension and OPEB		
	Cash Flow Hedge – Interest Rate	Amortization of Deferred Costs	Changes in Funded Status	Total
		(in millions)		
Balance in AOCI as of December 31, 2015	$ (9.1)	$ 2.6	$ (2.9)	$ (9.4)
Change in Fair Value Recognized in AOCI	—	—	(1.0)	(1.0)
Amount of (Gain) Loss Reclassified from AOCI				
Interest Expense (a)	2.7	—	—	2.7
Amortization of Prior Service Cost (Credit)	—	(1.8)	—	(1.8)
Amortization of Actuarial (Gains) Losses	—	0.7	—	0.7
Reclassifications from AOCI, before Income Tax (Expense) Benefit	2.7	(1.1)	—	1.6
Income Tax (Expense) Benefit	1.0	(0.4)	—	0.6
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	1.7	(0.7)	—	1.0
Net Current Period Other Comprehensive Income (Loss)	1.7	(0.7)	(1.0)	—
Balance in AOCI as of December 31, 2016	$ (7.4)	$ 1.9	$ (3.9)	$ (9.4)

(a) Amounts reclassified to the referenced line item on the statements of income.
(b) See Note 2 - New Accounting Pronouncements for additional information.

4. RATE MATTERS

The disclosures in this note apply to all Registrants unless indicated otherwise.

The Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. Rate matters can have a material impact on net income, cash flows and possibly financial condition. The Registrants' recent significant rate orders and pending rate filings are addressed in this note.

Impact of Tax Reform

Rate and regulatory matters are impacted by federal income tax implications. In December 2017, Tax Reform was enacted, which impacts outstanding rate and regulatory matters. For additional details on the impact of Tax Reform, see Note 12 - Income Taxes.

AEP Texas Rate Matters (Applies to AEP and AEP Texas)

AEP Texas Interim Transmission and Distribution Rates

As of December 31, 2018, AEP Texas' cumulative revenues from interim base rate increases from 2008 through 2018, subject to review, are estimated to be $1 billion. A base rate review could result in a refund to customers if AEP Texas incurs a disallowance of the transmission or distribution investment on which an interim increase was based. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring. A revenue decrease, including a refund of interim transmission and distribution rates, could reduce future net income and cash flows and impact financial condition.

In April 2018, the PUCT adopted a rule requiring investor-owned utilities operating solely within ERCOT to make periodic filings for rate proceedings. The rule requires AEP Texas to file for a comprehensive rate review no later than May 1, 2019.

In 2018, the PUCT issued approvals to increase AEP Texas' transmission rates by $22 million annually. The approvals included an increase in annual revenues to recover transmission capital additions of $46 million offset by a reduction in annual revenues of $24 million due to the reduction in the federal income tax rate due to Tax Reform. The approvals did not address the return of Excess ADIT benefits to customers.

In August 2018, the PUCT approved a Stipulation and Settlement agreement to amend AEP Texas' Distribution Cost Recovery Factor to reduce annual distribution rates by approximately $24 million annually, beginning September 1, 2018. The settlement included an increase in annual revenues to recover 2017 distribution capital additions of $19 million offset by reductions in annual revenues of: (a) $21 million due to the reduction in the federal income tax rate due to Tax Reform, (b) $10 million due to Excess ADIT associated with certain depreciable property to be amortized using ARAM and (c) $12 million due to Excess ADIT that is not subject to rate normalization requirements to be refunded over 5 years.

Hurricane Harvey and Texas Storm Cost Securitization

In August 2017, Hurricane Harvey hit the coast of Texas, causing power outages in the AEP Texas service territory. AEP Texas has a PUCT approved catastrophe reserve in base rates and can defer incremental storm expenses. AEP Texas currently recovers approximately $1 million of storm costs annually through base rates. As of December 31, 2018, the total balance of AEP Texas' regulatory asset for deferred storm costs is approximately $152 million, inclusive of approximately $129 million of incremental storm expenses related to Hurricane Harvey. See the table below for additional information on the Hurricane Harvey storm restoration costs:

	December 31, 2018			
Total Hurricane Harvey Storm Costs	**Capital**	**O&M**	**Regulatory Asset**	**Total**
		(in millions)		
Restoration Costs Incurred	$ 219.1	$ 136.9	$ —	$ 356.0
Incremental Operation and Maintenance Expenses (O&M)	—	(129.8)	129.8	—
Insurance Proceeds	(12.7)	—	(1.2)	(13.9)
Total Hurricane Harvey Storm Costs, Net	$ 206.4	$ 7.1	$ 128.6	$ 342.1

The securitization of storm cost recovery in Texas requires two filings with the PUCT. In August 2018, AEP Texas filed a Determination of System Restoration Costs (DSRC) with the PUCT for total estimated storm costs in the amount of $425 million, which includes estimated carrying costs. The total estimated storm costs net of insurance proceeds, tax credits received for the Disaster Tax Relief and Airport and Airway Extension Act of 2017, and Excess ADIT that is not subject to rate normalization requirements utilized to reduce the non-capital Hurricane Harvey costs is $370 million.

In November 2018, AEP Texas, the PUCT staff and intervenors filed a stipulation and settlement agreement with the PUCT that included all aspects of the DSRC filing with the following exceptions: (a) a $5 million permanent storm restoration reduction, (b) a $4 million disallowance of charges not directly related to storm restoration that will be included in a future regulatory proceeding and (c) a $5 million disallowance due to additional insurance proceeds received. See the table below for a reconciliation of the filed Determination of System Restoration Costs and settlement and stipulation agreement:

Total Estimated Storm Costs Requested in the DSRC		**December 31, 2018**
		(in millions)
Total Estimated Hurricane Harvey Storm Costs	$	356.0
Estimated Hurricane Harvey Carrying Costs		31.5
Estimated Litigation Costs		0.6
Non-Hurricane Harvey Storm Restoration Costs		36.5
Total Estimated Storm Costs requested in the DSRC		424.6
less:		
Tax Credit		(0.8)
Insurance Proceeds		(8.7)
Excess ADIT (a)		(45.5)
Total Estimated Storm Costs requested in the DSRC, after adjustments		369.6
less:		
Settlement Agreement Adjustments		(10.6)
Incremental Insurance Proceeds Received		(5.1)
Total Estimated Storm Costs per Settlement Agreement	$	353.9

(a) Amount represents Non-Hurricane Harvey Excess ADIT that is not subject to rate normalization requirements.

AEP Texas will seek to securitize estimated distribution related assets of $247 million in the first half of 2019 while the remaining $107 million of estimated transmission related assets is expected to be recovered through interim transmission filings or an upcoming base rate case. If these costs are not recovered, it could have an adverse effect on future net income, cash flows and financial condition.

APCo and WPCo Rate Matters (Applies to AEP and APCo)

Virginia Legislation Affecting Earnings Reviews

In 2015, amendments to Virginia law governing the regulation of investor-owned electric utilities were enacted. Under the amended Virginia law, APCo's existing generation and distribution base rates were frozen until after the Virginia SCC ruled on APCo's next biennial review. These amendments also precluded the Virginia SCC from performing biennial reviews of APCo's earnings for the years 2014 through 2017.

In March 2018, new Virginia legislation impacting investor-owned utilities was enacted, effective July 1, 2018, that: (a) on a one-time basis, required APCo to exclude $10 million of incurred fuel expenses from the July 2018 over/under recovery calculation, (b) reduced APCo's base rates by $50 million annually effective July 30, 2018, on an interim basis and subject to true-up, to reflect the reduction in the federal income tax rate due to Tax Reform, (c) will require APCo to file its next generation and distribution base rate case by March 31, 2020 using 2017, 2018 and 2019 test years ("triennial review"), (d) will require an adjustment in APCo's base rates on April 1, 2019 to reflect actual annual reductions in corporate income taxes due to Tax Reform, (e) will require APCo to seek approval from the Virginia

SCC for energy efficiency programs with projected costs in the aggregate of at least $140 million over the 10-year period ending July 1, 2028 and (f) will require APCo to construct and/or acquire solar generation facilities in Virginia, subject to approval of the Virginia SCC, of at least 200 MW of aggregate capacity by July 1, 2028.

Triennial reviews are subject to an earnings test which provides that 70% of any earnings exceeding 70 basis points over the Virginia SCC authorized return on common equity would be refunded, or may be offset by capital expenditures in Virginia SCC approved energy distribution grid transformation projects and/or new utility-owned solar and wind generation facilities. In November 2018, the Virginia SCC approved a return on common equity of 9.42% applicable to APCo base rate earnings for the 2017-2019 triennial period and rate adjustment clauses from November 2018 through November 2020. Management has reviewed APCo's actual and forecasted earnings for the triennial period and concluded that it is not probable but is reasonably possible that APCo will over-earn in Virginia during the 2017-2019 triennial period. Due to various uncertainties, including weather, storm restoration, weather-normalized demand and potential customer shopping during 2019, management cannot estimate a range of potential APCo Virginia over-earnings during the 2017-2019 triennial period. The Virginia triennial review of APCo earnings could materially reduce future net income and cash flows and impact financial condition.

Virginia Staff Depreciation Study Request

In November 2018, Virginia staff recommended that APCo implement new Virginia jurisdictional depreciation rates effective January 1, 2018 based on APCo's depreciation study that was prepared at Virginia staff's request using December 31, 2017 APCo property balances. Implementation of those depreciation rates would result in a $21 million pretax increase in annual depreciation expense ($6 million related to transmission) with no corresponding increase in retail base rates. In December 2018, APCo submitted a response to the Virginia staff stating that it was inappropriate for APCo to change Virginia depreciation rates in advance of the Virginia SCC's upcoming Triennial Review of APCo, citing the Virginia SCC's November 2014 order to not change APCo's Virginia depreciation rates until APCo's next base rate case/review. If the Virginia SCC were to issue an order approving the Virginia staff's recommended retroactive change in APCo's Virginia depreciation rates, it would reduce future net income and cash flows and impact financial condition.

Virginia Tax Reform

In October 2018, the Virginia SCC issued an order approving APCo's request to refund $55 million of Excess ADIT that is not subject to rate normalization requirements to customers through a rider. The rider is being paid over twelve months effective November 1, 2018 and will offset APCo's recent increase in interim fuel rates, subject to refund, as approved by the Virginia SCC.

In October 2018, APCo also submitted a filing with the Virginia SCC to resolve outstanding issues related to Tax Reform. The filing incorporated the $50 million being refunded to customers as disclosed in "Virginia Legislation Affecting Earnings Reviews" above and, if approved, will reduce APCo's base rates by an additional $7 million annually. The combined reduction in APCo's base rates due to Tax Reform will refund: (a) $39 million annually of excess federal income taxes collected since January 1, 2018 until new base rates are implemented, (b) $7 million annually of Excess ADIT associated with certain depreciable property using ARAM and (c) $11 million annually of Excess ADIT that is not subject to rate normalization requirements over 10 years.

In November 2018, the Virginia SCC staff filed testimony recommending a total annual reduction in APCo's base rates of $69 million. The proposed reduction consisted of: (a) $41 million annually of excess federal income taxes collected since January 1, 2018 until new base rates are implemented, (b) $9 million annually of Excess ADIT associated with certain depreciable property using ARAM and (c) $19 million annually of Excess ADIT that is not subject to rate normalization requirements over 5 years. The Virginia SCC staff also recommended that APCo provide a one-time credit of $23 million for estimated excess taxes collected from customers during the 15-month period ending March 31, 2019. Intervenors filed testimony recommending that the $23 million for estimated excess taxes collected from customers during the 15-month period ending March 31, 2019 be refunded over 1 year and Excess ADIT that is not subject to rate normalization requirements be refunded over 3 years.

In December 2018, APCo filed rebuttal testimony with the Virginia SCC generally agreeing with the Virginia SCC staff testimony. A hearing at the Virginia SCC was held in January 2019 where both APCo and the Virginia SCC staff lowered their reduction for excess federal income taxes collected since January 1, 2018 by $1 million. APCo anticipates a final order from the Virginia SCC by the end of the first quarter of 2019 and expects to implement additional customer rate credits in a tax-related rider starting in April 2019. The Virginia SCC's review of APCo's Tax Reform filing could reduce future net income and cash flows and impact financial condition.

2018 West Virginia Base Rate Case

In May 2018, APCo and WPCo filed a joint request with the WVPSC to increase their combined West Virginia base rates by $115 million ($98 million related to APCo) annually based on a 10.22% return on common equity. The proposed annual increase included $32 million ($28 million related to APCo) due to increased annual depreciation expense and reflected the impact of the reduction in the federal income tax rate due to Tax Reform. In October 2018, APCo and WPCo filed updated schedules supporting a $95 million ($80 million related to APCo) annual increase in West Virginia base rates primarily due to the impact of West Virginia Tax Reform case discussed below.

In November 2018 APCo, WPCo, WVPSC staff and certain intervenors filed a Stipulation and Settlement agreement with the WVPSC. The agreement included a proposed annual base rate increase of $44 million ($36 million related to APCo) based upon a 9.75% return on common equity effective March 2019. The agreement provided for an annual increase of $18 million ($14 million related to APCo) due to increased annual depreciation expense. Depreciation rates were decreased from the original request primarily due to continuing with a 2040 retirement date for Clinch River Plant rather than APCo's proposed retirement date of 2025. The agreement also included: (a) a proposal to refund, through a rider, $24 million ($19 million related to APCo) of Excess ADIT that is not subject to rate normalization requirements over two years starting March 2019, (b) a proposal to utilize $14 million ($12 million related to APCo) of Excess ADIT that is not subject to rate normalization requirements to offset regulatory asset balances relating to ENEC, (c) an agreement to work with the WVPSC to establish economic incentive programs and (d) an agreement, barring any unforeseen events, to not initiate another base rate proceeding prior to April 1, 2020. An order from the WVPSC is expected in the first quarter 2019. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

West Virginia Tax Reform

In August 2018, the WVPSC approved a settlement agreement between APCo, WPCo and various intervenors that addresses the reduction in the federal income tax rate due to Tax Reform and provides refunds to customers, through a rider, effective September 1, 2018 of approximately $63 million ($51 million related to APCo) through June 2020. In addition, per the agreement, APCo and WPCo utilized $139 million ($125 million related to APCo) of current tax savings and Excess ADIT that is not subject to rate normalization requirements to offset regulatory asset balances related to carbon capture, storm damage, ENEC and vegetation management. The WVPSC order indicated that the remaining balance of Excess ADIT that is not subject to rate normalization requirements would be addressed at a later date.

ETT Rate Matters (Applies to AEP)

ETT Interim Transmission Rates

AEP has a 50% equity ownership interest in ETT. Predominantly all of ETT's revenues are based on interim rate changes that can be filed twice annually and are subject to review and possible true-up in the next filed base rate proceeding. Through December 31, 2018, AEP's share of ETT's cumulative revenues that are subject to review is estimated to be $884 million. A base rate review could produce a refund if ETT incurs a disallowance of the transmission investment on which an interim increase was based. A revenue decrease, including a refund of interim transmission rates, could reduce future net income and cash flows and impact financial condition. Management is unable to determine a range of potential losses, if any, that are reasonably possible of occurring.

In April 2018, the PUCT adopted a rule requiring investor-owned utilities operating solely inside ERCOT to make periodic filings for rate proceedings. The rule requires ETT to file for a comprehensive rate review no later than February 1, 2021.

In June 2018, the PUCT approved ETT's application to reduce its transmission rates by $28 million annually, beginning June 21, 2018, to reflect the reduction in the federal income tax rate due to Tax Reform. The filing did not address the return of Excess ADIT benefits to customers.

In December 2018, the PUCT approved ETT's request to refund $11 million of excess federal income taxes collected in 2018 prior to the reduction in transmission rates that were implemented on June 21, 2018. The refunds were completed in December 2018.

<u>I&M Rate Matters</u> (Applies to AEP and I&M)

2017 Indiana Base Rate Case

In 2017, I&M filed a request with the IURC for a $263 million annual increase in Indiana rates based upon a proposed 10.6% return on common equity. In February 2018, I&M filed a Stipulation and Settlement Agreement for a $97 million annual increase, based on a 9.95% return on equity, in Indiana rates effective July 1, 2018 subject to a temporary offsetting reduction to customer bills through December 2018 for a credit rider related to the timing of estimated in-service dates of certain capital expenditures. In May 2018, the IURC issued an order approving the Stipulation and Settlement Agreement.

2017 Michigan Base Rate Case

In 2017, I&M filed a request with the MPSC for a $52 million annual increase in Michigan base rates based upon a proposed 10.6% return on common equity. In February 2018, an MPSC ALJ issued a Proposal for Decision and recommended an annual revenue increase of $49 million, including an intervenor's proposal for up to 10% of I&M's Michigan retail customers to choose an alternate supplier for generation and a proposed capacity rate based on PJM's net cost of new entry value of $289/MW-day, as well as the MPSC staff's recommended calculation of depreciation expense for both units of Rockport Plant through 2028 and a return on common equity of 9.8%. In April 2018, the MPSC issued an order that generally approved the ALJ proposal resulting in an annual revenue increase of $50 million, effective April 2018 based on a 9.9% return on common equity. The MPSC also approved the ALJ's recommendation related to the capacity rate.

If the maximum 10% of customers choose an alternate supplier starting in February 2019, the estimated annual pretax loss due to the reduced capacity rate would be approximately $9 million. In October 2018, I&M filed a request with the MPSC seeking authority to defer costs related to customers choosing an alternate supplier starting in February 2019. In December 2018, the MPSC rejected I&M's request.

Michigan Tax Reform

In August 2018, the MPSC approved I&M's application to refund, through a rider, approximately $9 million annually for the impact of Tax Reform on I&M's Michigan jurisdictional earnings effective September 1, 2018. In October 2018, I&M also made two filings with the MPSC recommending to: (a) refund $3 million over eight months for the impact of Tax Reform on Michigan jurisdictional earnings for the period April 26, 2018 through August 31, 2018, (b) refund approximately $68 million of Excess ADIT associated with certain depreciable property using ARAM and (c) refund approximately $37 million of Excess ADIT that is not subject to rate normalization requirements over 10 years. In January 2019, I&M received an order from the MPSC requiring I&M to refund $5 million over six months, effective February 2019, for the Michigan jurisdictional impacts of Tax Reform related to the period January 1, 2018 through August 31, 2018. An order from the MPSC regarding Excess ADIT is expected in the first half of 2019.

Rockport Plant, Unit 2 SCR

In 2016, I&M filed an application with the IURC for approval of a Certificate of Public Convenience and Necessity (CPCN) to install SCR technology at Rockport Plant, Unit 2. The equipment will allow I&M to reduce emissions of NO_x from Rockport Plant, Unit 2 in order for I&M to continue to operate that unit under current environmental requirements and is expected to be placed in service in May 2020. The estimated cost of the SCR project is $274 million, excluding AFUDC, to be shared equally between I&M and AEGCo. The filing included a request for authorization for I&M to defer and recover, through a rider, its Indiana jurisdictional ownership share of costs including investment carrying costs at a weighted average cost of capital (WACC), depreciation over a 10-year period as provided by statute and other related expenses.

In March 2018, the IURC issued an order approving: (a) the CPCN, (b) the $274 million estimated cost of the SCR, excluding AFUDC, (c) deferral of the Indiana jurisdictional ownership share of costs, including investment carrying costs, (d) depreciation of the SCR asset over 10 years and (e) recovery of these costs using an I&M Indiana rider.

Management intends to request recovery of the Michigan jurisdictional share of the SCR project in a future base rate case. If the Michigan jurisdictional share of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition. The AEGCo ownership share of the SCR project will be billable under the Rockport UPA to I&M and KPCo and will be subject to future regulatory approval for recovery.

<u>KPCo Rate Matters</u> (Applies to AEP)

2017 Kentucky Base Rate Case

In January 2018, the KPSC issued an order approving a non-unanimous settlement agreement with certain modifications resulting in an annual revenue increase of $12 million, effective January 2018, based on a 9.7% return on equity. The KPSC's primary revenue requirement modification to the settlement agreement was a $14 million annual revenue reduction for the decrease in the corporate federal income tax rate due to Tax Reform. The KPSC approved: (a) the deferral of a total of $50 million of Rockport Plant UPA expenses for the years 2018 through 2022, with the manner and timing of recovery of the deferral to be addressed in KPCo's next base rate case, (b) the recovery/return of 80% of certain annual PJM OATT expenses above/below the corresponding level recovered in base rates, (c) KPCo's commitment to not file a base rate case for three years with rates effective no earlier than 2021 and (d) increased depreciation expense based upon updated Big Sandy Plant, Unit 1 depreciation rates using a 20-year depreciable life.

In February 2018, KPCo filed with the KPSC for rehearing of the January 2018 base case order. In June 2018, the KPSC issued an order approving an additional revenue increase of $765 thousand related to the calculation of federal income tax expense. This rate increase was effective June, 2018.

Kentucky Tax Reform

In June 2018, the KPSC issued an order approving a settlement agreement between KPCo and an intervenor that stipulates that KPCo will refund an estimated $82 million of Excess ADIT associated with certain depreciable property using ARAM and an estimated $93 million of Excess ADIT that is not subject to rate normalization requirements over 18 years. The refund was effective July 1, 2018.

<u>OPCo Rate Matters</u> (Applies to AEP and OPCo)

Ohio Electric Security Plan Filings

June 2015 - May 2018 ESP Including PPA Application and Proposed ESP Extension through 2024

In 2013, OPCo filed an application with the PUCO to approve an ESP that included proposed rate adjustments and the continuation and modification of certain existing riders, including the DIR, effective June 2015 through May 2018.

The proposal also involved a PPA rider that would include OPCo's OVEC contractual entitlement (OVEC PPA) and would allow retail customers to receive a rate stabilizing charge or credit by hedging market-based prices with a cost-based PPA.

In 2015 and 2016, the PUCO issued orders in this proceeding. As part of the issued orders, the PUCO approved: (a) the DIR with modified revenue caps, (b) recovery of OVEC-related net margin incurred beginning June 2016, (c) potential additional contingent customer credits of up to $15 million to be included in the PPA rider over the final four years of the PPA rider and (d) the limitation that OPCo will not flow through any capacity performance penalties or bonuses through the PPA rider. Additionally, subject to cost recovery and PUCO approval, OPCo agreed to develop and implement, by 2021, a solar energy project(s) of at least 400 MWs and a wind energy project(s) of at least 500 MWs, with 100% of all output to be received by OPCo. AEP affiliates could own up to 50% of these solar and wind projects.

In 2017, the PUCO rejected all pending rehearing requests related to the OVEC PPA. In June 2017, intervenors filed appeals to the Supreme Court of Ohio stating that the PUCO's approval of the OVEC PPA was unlawful and does not provide customers with rate stability. In June 2018, oral arguments were held before the Supreme Court of Ohio. In November 2018, the Ohio Supreme Court unanimously affirmed the PUCO's order in the June 2015 - May 2018 ESP and PPA Rider cases.

In 2016, OPCo refiled its amended ESP extension application and supporting testimony, consistent with the terms of the modified and approved stipulation agreement and based upon a 2016 PUCO order. The amended filing proposed to extend the ESP through May 2024.

In 2017, OPCo and various intervenors filed a stipulation agreement with the PUCO. The stipulation extends the term of the ESP through May 2024 and includes: (a) an extension of the OVEC PPA rider, (b) a proposed 10% return on common equity on capital costs for certain riders, (c) the continuation of riders previously approved in the June 2015 - May 2018 ESP, (d) rate caps related to OPCo's DIR ranging from $215 million to $290 million for the periods 2018 through 2021 and (e) the addition of various new riders, including a Smart City Rider and a Renewable Generation Rider. DIR rate caps will be reset in OPCo's next distribution base rate case which must be filed by June 2020.

In April 2018, the PUCO issued an order approving the ESP extension stipulation agreement, with no significant changes. In May 2018, OPCo and various intervenors filed requests for rehearing with the PUCO. In June 2018, these requests for rehearing were approved to allow further consideration of the requests. In August 2018, the PUCO denied all requests for rehearing. In October 2018, an appeal was filed with the Ohio Supreme Court challenging various approved riders. If the Ohio Supreme Court reverses the PUCO's decision, it could reduce future net income and cash flows and impact financial condition.

2016 SEET Filing

Ohio law provides for the return of significantly excessive earnings to ratepayers upon PUCO review. Significantly excessive earnings are measured by whether the earned return on common equity of the electric utility is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that face comparable business and financial risk.

In 2016, OPCo recorded a 2016 SEET provision of $58 million based upon projected earnings data for companies in the comparable utilities risk group. In determining OPCo's return on equity in relation to the comparable utilities risk group, management excluded the following items resolved in OPCo's Global Settlement that was filed at the PUCO in December 2016 and subsequently approved in February 2017: (a) gain on the deferral of RSR costs, (b) refunds to customers related to the SEET remands and (c) refunds to customers related to fuel adjustment clause proceedings.

In 2017, OPCo submitted its 2016 SEET filing with the PUCO in which management indicated that OPCo did not have significantly excessive earnings in 2016 based upon actual earnings data for the comparable utilities risk group.

In January 2018, PUCO staff filed testimony that OPCo did not have significantly excessive earnings in 2016. Also in January 2018, an intervenor filed testimony recommending a $53 million refund to customers related to OPCo 2016 SEET earnings. In February 2018, OPCo and PUCO staff filed a stipulation agreement in which both parties agreed that OPCo did not have significantly excessive earnings in 2016.

A 2016 SEET hearing was held in April 2018 and management expects to receive an order in the first half of 2019. While management believes that OPCo's adjusted 2016 earnings were not excessive, management did not adjust OPCo's 2016 SEET provision due to risks that the PUCO could rule against OPCo's proposed SEET adjustments, including treatment of the Global Settlement issues described above, adjust the comparable risk group or adopt a different 2016 SEET threshold. If the PUCO orders a refund of 2016 OPCo earnings, it could negatively affect future SEET filings, reduce future net income and cash flows and impact financial condition.

Ohio Tax Reform

In October 2018, the PUCO issued an order approving a September 2018 settlement agreement between OPCo and various intervenors that addresses the reduction in the federal income tax rate due to Tax Reform. The settlement will: (a) refund excess federal income tax of $20 million annually, through a rider, effective January 1, 2018 until new base rates are implemented, (b) refund an estimated $278 million of Excess ADIT associated with depreciable property through OPCo's DIR using ARAM, (c) utilize $48 million of Excess ADIT that is not subject to rate normalization to offset regulatory asset balances related to OPCo's distribution decoupling program and (d) refund the remaining estimated $129 million of Excess ADIT that is not subject to rate normalization by December 31, 2024 through a rider beginning in the fourth quarter of 2018.

<u>PSO Rate Matters</u> (Applies to AEP and PSO)

2018 Oklahoma Base Rate Case

In October 2018, PSO filed a request with the OCC for an $88 million annual increase in Oklahoma retail rates based upon a 10.3% return on common equity. PSO also proposed to implement a performance-based rate plan that combines a formula rate with a set of customer-focused performance incentive measures related to reliability, public safety, customer satisfaction and economic development. The proposed annual increase includes $13 million related to increased annual depreciation rates and $7 million related to increased storm expense amortization. The requested increase in annual depreciation rates includes the recovery of Oklaunion Power Station through 2028 (currently being recovered in rates through 2046). Management has announced plans to retire Oklaunion Power Station by October 2020.

In January 2019, OCC staff and various intervenors filed testimony. OCC staff recommended a $57 million annual rate increase based on a 9% return on common equity while intervenor recommendations ranged from a decrease in rates of $6 million to an increase in rates of $34 million based on a return on common equity ranging from 9.3% to 9.36%, respectively. The difference between PSO's requested annual base rate increase and the OCC staff and intervenors recommendations are primarily due to: (a) a reduction in the requested return on common equity, (b) a rejection to PSO's request to increase depreciation rates, including the proposed accelerated recovery of the Oklaunion Power Station through 2028, (c) a disallowance of certain incentives and operation and maintenance expenses and (d) a proposal to refund Excess ADIT that is not subject to rate normalization requirements over 5 years instead of 10 years. In addition, certain parties recommended a debt only return on, or no recovery of, PSO's estimated remaining net book value in the Oklaunion Power Station after its retirement, which is estimated to be $49 million. Also, a party recommended a potential refund of $9 million related to an SPP rider claiming that PSO did not adequately support the related costs. No parties supported PSO's performance-based rate plan as filed.

In February 2019, PSO filed testimony rebutting the various parties' recommendations included above. PSO also proposed that the performance-based rate plan be implemented on a one-year trial basis where it could be reevaluated at the conclusion of the trial period. In addition, PSO agreed that the prudence of capital investment would be deferred

until PSO's next base rate case. A hearing at the OCC is scheduled to begin in March 2019. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Oklahoma Tax Reform

In August 2018, the OCC issued an order that approved PSO's compliance filing that addresses the reduction in the federal income tax rate due to Tax Reform. As a result of the order PSO implemented a rider in September 2018 to: (a) refund $3 million of excess federal income taxes collected from January 9, 2018 through February 28, 2018 by the end of 2018, (b) refund an estimated $353 million of Excess ADIT associated with certain depreciable property using ARAM and (c) refund an estimated $72 million of Excess ADIT that is not subject to rate normalization requirements over 10 years.

<u>SWEPCo Rate Matters</u> (Applies to AEP and SWEPCo)

2012 Texas Base Rate Case

In 2012, SWEPCo filed a request with the PUCT to increase annual base rates primarily due to the completion of the Turk Plant. In 2013, the PUCT issued an order affirming the prudence of the Turk Plant but determined that the Turk Plant's Texas jurisdictional capital cost cap established in a previous Certificate of Convenience and Necessity case also limited SWEPCo's recovery of AFUDC in addition to limits on its recovery of cash construction costs.

Upon rehearing in 2014, the PUCT reversed its initial ruling and determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result, SWEPCo reversed $114 million of a previously recorded regulatory disallowance in 2013. The resulting annual base rate increase was approximately $52 million. In 2017, the Texas District Court upheld the PUCT's 2014 order and intervenors filed appeals with the Texas Third Court of Appeals.

In July 2018, the Texas Third Court of Appeals reversed the PUCT's judgment affirming the prudence of the Turk Plant and remanded the issue back to the PUCT. In August 2018, SWEPCo filed a Motion for Reconsideration at the Court of Appeals, which was denied. In January 2019, SWEPCo and the PUCT filed petitions for review with the Texas Supreme Court.

As of December 31, 2018, the net book value of Turk Plant was $1.5 billion, before cost of removal, including materials and supplies inventory and CWIP. If certain parts of the PUCT order are overturned and if SWEPCo cannot ultimately fully recover its approximate 33% Texas jurisdictional share of the Turk Plant investment, including AFUDC, it could reduce future net income and cash flows and impact financial condition.

2016 Texas Base Rate Case

In 2016, SWEPCo filed a request with the PUCT for a net increase in Texas annual revenues of $69 million based upon a 10% return on common equity. In January 2018, the PUCT issued a final order approving a net increase in Texas annual revenues of $50 million based upon a return on common equity of 9.6%, effective May 2017. The final order also included: (a) approval to recover the Texas jurisdictional share of environmental investments placed in service, as of June 30, 2016, at various plants, including Welsh Plant, Units 1 and 3, (b) approval of recovery of, but no return on, the Texas jurisdictional share of the net book value of Welsh Plant, Unit 2, (c) approval of $2 million in additional vegetation management expenses and (d) the rejection of SWEPCo's proposed transmission cost recovery mechanism.

As a result of the final order, in 2017 SWEPCo: (a) recorded an impairment charge of $19 million, which included $7 million associated with the lack of return on Welsh Plant, Unit 2 and $12 million related to other disallowed plant investments, (b) recognized $32 million of additional revenues, for the period of May 2017 through December 2017, that was surcharged to customers in 2018 and (c) recognized an additional $7 million of expenses consisting primarily of depreciation expense and vegetation management expense, offset by the deferral of rate case expense. SWEPCo

implemented new rates in February 2018 billings. The $32 million of additional 2017 revenues was collected during 2018. In March 2018, the PUCT clarified and corrected portions of the final order, without changing the overall decision or amounts of the rate change. The order has been appealed by various intervenors.

In April 2018, SWEPCo made an income tax rate refund tariff filing which includes an annual revenue reduction of approximately $18 million to reflect the difference between rates collected under the final order and the rates that would be collected under Tax Reform. The filing did not address the return of Excess ADIT benefits to customers. In June 2018, the ALJ issued an order approving interim rates that provided for a reduction of residential rates of $8 million that began in June 2018. In September 2018, the ALJ issued an order approving interim rates for the remaining customers that began in November 2018. In December 2018, the PUCT issued an order approving the new rates.

Texas Tax Reform

In October 2018, SWEPCo filed a Stipulation and Settlement Agreement with the PUCT to refund $10 million of excess federal income taxes collected, as a result of Tax Reform, from January 1, 2018 through June 14, 2018 for residential customers and January 1, 2018 through September 19, 2018 for all other customer classes. An interim order was issued by an ALJ and the refunds were made to customers through a rider in the fourth quarter of 2018. In December 2018, the PUCT issued an order approving the settlement agreement.

2015 Louisiana Formula Rate Filing

In 2015, SWEPCo filed its formula rate plan for test year 2014 with the LPSC. The filing included a $14 million annual increase, which was effective August 2015. In December 2018, the LPSC issued an order approving the increase as filed.

2017 Louisiana Formula Rate Filing

In 2017, the LPSC approved an uncontested stipulation agreement that SWEPCo filed for its formula rate plan for test year 2015. The filing included a net annual increase not to exceed $31 million, which was effective May 2017 and includes SWEPCo's Louisiana jurisdictional share of Welsh Plant and Flint Creek Plant environmental controls which were placed in service in 2016. Also in 2017, SWEPCo filed testimony in Louisiana supporting the prudence of its environmental control investment for Welsh Plant, Units 1 and 3 and Flint Creek power plants. These environmental costs were subject to prudence review by the LPSC. In August 2018, the LPSC issued an order affirming prudence and approved the settlement agreement for the environmental control investment. In December 2018, the LPSC issued an order approving the $31 million increase as filed.

2018 Louisiana Formula Rate Filing

In April 2018, SWEPCo filed its formula rate plan for test year 2017 with the LPSC. The filing included a net $28 million annual increase, which was effective August 2018 and included SWEPCo's Louisiana jurisdictional share of Welsh Plant and Flint Creek Plant environmental controls. The filing also included a reduction in the federal income tax rate due to Tax Reform but did not address the return of Excess ADIT benefits to customers.

In July 2018, SWEPCo made a supplemental filing to its formula rate plan with the LPSC to reduce the requested annual increase to $18 million. The difference between SWEPCo's requested $28 million annual increase and the $18 million annual increase in the supplemental filing is primarily the result of the return of Excess ADIT benefits to customers.

In October 2018, the LPSC staff issued a recommendation that SWEPCo refund $11 million of excess federal income taxes collected, as a result of Tax Reform, from January 1, 2018 through July 31, 2018. A decision by the LPSC is expected in 2019.

If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Welsh Plant - Environmental Impact

Management currently estimates that the investment necessary to meet proposed environmental regulations through 2025 for Welsh Plant, Units 1 and 3 could total approximately $550 million, excluding AFUDC. As of December 31, 2018, SWEPCo had incurred costs of $399 million, including AFUDC, related to these projects. Management continues to evaluate the impact of environmental rules and related project cost estimates. As of December 31, 2018, the total net book value of Welsh Plant, Units 1 and 3 was $629 million, before cost of removal, including materials and supplies inventory and CWIP.

In 2016, as approved by the APSC, SWEPCo began recovering $79 million related to the Arkansas jurisdictional share of these environmental costs, subject to prudence review in the next Arkansas filed base rate proceeding. In 2017, the LPSC approved recovery of $131 million in investments related to its Louisiana jurisdictional share of environmental controls installed at Welsh Plant. SWEPCo's approved Louisiana jurisdictional share of Welsh Plant deferrals: (a) are $10 million, excluding $5 million of unrecognized equity as of December 31, 2018, (b) is subject to review by the LPSC and (c) includes a WACC return on environmental investments and the related depreciation expense and taxes. See "2017 Louisiana Formula Rate Filing" and "2018 Louisiana Formula Rate Filing" disclosures above.

If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Arkansas Tax Reform

In September 2018, the APSC issued an order that approved SWEPCo's application to implement a rider for SWEPCo's Arkansas jurisdiction to address the reduction in the federal income tax rate due to Tax Reform. The rider was implemented in the first billing cycle of October 2018 to: (a) refund $7 million over 15 months of excess federal income taxes collected from January 1, 2018 through September 30, 2018, (b) refund an ongoing estimated $655 thousand monthly from October 1, 2018 until new base rates go into effect as a result of a subsequent APSC order, (c) refund an estimated $66 million of Excess ADIT associated with certain depreciable property using ARAM and (d) refund an estimated $11 million of Excess ADIT that is not subject to rate normalization requirements over 15 months.

FERC Rate Matters

PJM Transmission Rates (Applies to AEP, APCo, I&M and OPCo)

In 2016, PJM transmission owners, including AEP's transmission owning subsidiaries within PJM, and various state commissions filed a settlement agreement at the FERC to resolve outstanding issues related to cost responsibility for charges to transmission customers for certain transmission facilities that operate at or above 500 kV. In May 2018, the FERC approved the settlement agreement. PJM implemented a transmission enhancement charge adjustment through the PJM OATT, which will be billable through 2025. Management expects that any refunds received would generally be returned to retail customers through existing state rider mechanisms and has recorded $98 million to Customer Accounts Receivable and $68 million to Deferred Charges and Other Noncurrent Assets, with offsets to Regulatory Liabilities and Deferred Investment Tax Credits as of December 31, 2018.

FERC Transmission Complaint - AEP's PJM Participants (Applies to AEP, AEPTCo, APCo, I&M and OPCo)

In 2016, seven parties filed a complaint at the FERC that alleged the base return on common equity used by AEP's transmission owning subsidiaries within PJM in calculating formula transmission rates under the PJM OATT is excessive and should be reduced from 10.99% to 8.32%, effective upon the date of the complaint. In 2017, a FERC order set the matter for hearing and settlement procedures. In March 2018, AEP's transmission owning subsidiaries within PJM and six of the complainants filed a settlement agreement with the FERC (the seventh complainant abstained). If approved by the FERC, the settlement agreement: (a) establishes a base ROE for AEP's transmission owning subsidiaries within PJM of 9.85% (10.35% inclusive of the RTO incentive adder of 0.5%), effective January 1, 2018, (b) requires AEP's transmission owning subsidiaries within PJM to provide a one-time refund of $50 million, attributable from the date of the complaint through December 31, 2017, which was credited to customer bills in the second quarter

of 2018 and (c) increases the cap on the equity portion of the capital structure to 55% from 50%. As part of the settlement agreement, AEP's transmission owning subsidiaries within PJM also filed updated transmission formula rates incorporating the reduction in the corporate federal income tax rate due to Tax Reform, effective January 1, 2018 and providing for the amortization of the portion of the Excess ADIT that is not subject to the normalization method of accounting, ratably over a ten-year period through credits to the federal income tax expense component of the revenue requirement. In April 2018, an ALJ accepted the interim settlement rates, which included the $50 million one-time refund that occurred in the second quarter of 2018. These interim rates are subject to refund or surcharge, with interest.

In April 2018, certain intervenors filed comments at the FERC recommending a base ROE of 8.48% and a one-time refund of $184 million. The FERC trial staff filed comments recommending a base ROE of 8.41% and a one-time refund of $175 million. Another intervenor recommended the refund be calculated in accordance with the base ROE that will ultimately be approved by the FERC. In May 2018, management filed reply comments providing further support for the 9.85% base ROE agreed to in the settlement agreement. In February 2019, the FERC issued an order that requested additional information in order to evaluate the settlement. That order did not rule on the merits of the settlement.

If the FERC orders revenue reductions in excess of the terms of the settlement agreement, it could reduce future net income and cash flows and impact financial condition.

Modifications to AEP's PJM Transmission Rates (Applies to AEP, AEPTCo, APCo, I&M and OPCo)

In 2016, AEP's transmission owning subsidiaries within PJM filed an application at the FERC to modify the PJM OATT formula transmission rate calculation, including an adjustment to recover a tax-related regulatory asset and a shift from historical to projected expenses. The modified PJM OATT formula rates are based on projected calendar year financial activity and projected plant balances. In 2017, AEP's transmission owning subsidiaries within PJM filed an uncontested settlement agreement with the FERC resolving all outstanding issues. In April 2018, the FERC approved the uncontested settlement agreement and rates were implemented effective January 1, 2018.

FERC Transmission Complaint - AEP's SPP Participants (Applies to AEP, AEPTCo, PSO and SWEPCo)

In 2017, several parties filed a complaint at the FERC that states the base return on common equity used by AEP's transmission owning subsidiaries within SPP in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.36%, effective upon the date of the complaint through September 5, 2018. A FERC order set the matter for hearing and settlement procedures. The parties were unable to settle and the proceeding is currently in the hearing phase.

In September 2018, the same parties filed another complaint at the FERC that states the base return on common equity used by AEP's transmission owning subsidiaries within SPP in calculating formula transmission rates under the SPP OATT is excessive and should be reduced from 10.7% to 8.71%, effective upon the date of the second complaint. A hearing at the FERC is scheduled for August 2019.

Management believes its financial statements adequately address the impact of these complaints. If the FERC orders revenue reductions as a result of these complaints, including refunds from the date of the complaint filings, it could reduce future net income and cash flows and impact financial condition.

Modifications to AEP's SPP Transmission Rates (Applies to AEP, AEPTCo, PSO and SWEPCo)

In 2017, AEP's transmission owning subsidiaries within SPP filed an application at the FERC to modify the SPP OATT formula transmission rate calculation, including an adjustment to recover a tax-related regulatory asset and a shift from historical to projected expenses. The modified SPP OATT formula rates are based on projected calendar year financial activity and projected plant balances. The FERC accepted the proposed modifications effective January 1, 2018, subject to refund. In February 2019, AEP's transmission owning subsidiaries within SPP filed an uncontested settlement agreement with the FERC, subject to FERC approval, resolving all outstanding issues. If the FERC determines that any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

FERC SWEPCo Power Supply Agreements Complaint - East Texas Electric Cooperative, Inc. (ETEC) and Northeast Texas Electric Cooperative, Inc. (NTEC) (Applies to AEP and SWEPCo)

In 2017, ETEC and NTEC filed a complaint at the FERC that states the base return on common equity used by SWEPCo in calculating its power supply formula rates is excessive and should be reduced from 11.1% to 8.41%, effective upon the date of the complaint. A FERC order set the matter for hearing and settlement procedures.

In July 2018, the FERC issued an order approving a settlement agreement between SWEPCo, ETEC and NTEC that resolves the issues of the complaint. The order: (a) reduced the base return on common equity from 11.1% to 10.1% effective September 1, 2017, (b) required SWEPCo to provide a one-time billing credit of $287 thousand to reflect the decrease in return on common equity from September 1, 2017 through December 31, 2017 and (c) implemented the lower return on common equity on contracts starting January 1, 2018.

5. EFFECTS OF REGULATION

The disclosures in this note apply to all Registrants unless indicated otherwise.

Regulated Generating Unit to be Retired by 2020 (Applies to AEP and PSO)

In September 2018, management announced that the Oklaunion Power Station is probable of abandonment and is to be retired by October 2020. The table below summarizes the plant investment and cost of removal, currently being recovered, as well as the regulatory asset for accelerated depreciation for the generating unit as of December 31, 2018. See "2018 Oklahoma Base Rate Case" section of Note 4 for additional information.

Gross Investment	Accumulated Depreciation	Net Investment	Accelerated Depreciation Regulatory Asset (a)	Materials and Supplies	Cost of Removal Regulatory Liability	Expected Retirement Date	Remaining Recovery Period
			(dollars in millions)				
$ 106.6	$ 62.8	$ 43.8	$ 5.5	$ 3.1	$ 5.0	2020	28 years

(a) In October 2018, PSO changed depreciation rates to utilize the 2020 end-of-life and defer depreciation expense to a regulatory asset for the amount in excess of the previously OCC-approved depreciation rates for Oklaunion Power Station. See "2018 Oklahoma Base Rate Case" section of Note 4 for additional information.

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	AEP		
	December 31, 2018	December 31, 2017	Remaining Recovery Period
Current Regulatory Assets	(in millions)		
Under-recovered Fuel Costs - earns a return	$ 101.7	$ 203.1	1 year
Under-recovered Fuel Costs - does not earn a return	48.4	89.4	1 year
Total Current Regulatory Assets	$ 150.1	$ 292.5	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	$ 50.3	$ 50.3	
Kentucky Deferred Purchased Power Expenses	14.5	—	
Other Regulatory Assets Pending Final Regulatory Approval	14.8	9.6	
Total Regulatory Assets Currently Earning a Return	79.6	59.9	
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs (a)	152.4	128.0	
Plant Retirement Costs - Asset Retirement Obligation Costs	35.3	39.7	
Cook Plant Uprate Project	—	36.3	
Cook Plant Turbine	—	15.9	
Other Regulatory Assets Pending Final Regulatory Approval	20.7	42.2	
Total Regulatory Assets Currently Not Earning a Return	208.4	262.1	
Total Regulatory Assets Pending Final Regulatory Approval (b)	288.0	322.0	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	680.9	682.6	25 years
Meter Replacement Costs	74.4	83.7	9 years
Plant Retirement Costs - Asset Retirement Obligation Costs	64.3	34.3	22 years

Ohio Capacity Deferral	57.8	172.6	1 year
Advanced Metering System	45.3	33.5	2 years
Environmental Control Projects	43.4	28.1	22 years
Cook Plant Uprate Project	35.0	—	15 years
Storm-Related Costs	31.1	39.3	4 years
Mitchell Plant Transfer - West Virginia	17.0	17.8	22 years
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	16.1	—	16 years
Cook Plant Turbine	15.8	—	20 years
Ohio Distribution Decoupling	12.3	61.7	2 years
Ohio Basic Transmission Cost Rider	—	90.8	
Other Regulatory Assets Approved for Recovery	46.1	49.4	various
Total Regulatory Assets Currently Earning a Return	1,139.5	1,293.8	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	1,326.6	1,196.3	12 years
Unamortized Loss on Reacquired Debt	134.2	129.9	30 years
Unrealized Loss on Forward Commitments	104.6	139.3	14 years
Cook Plant Nuclear Refueling Outage Levelization	37.5	66.7	3 years
Postemployment Benefits	35.6	39.1	4 years
Peak Demand Reduction/Energy Efficiency	31.9	40.1	8 years
Medicare Subsidy	27.9	32.5	6 years
Vegetation Management - West Virginia	26.6	33.5	3 years
PJM/SPP Annual Formula Rate True Up	22.0	11.7	2 years
Plant Retirement Costs - Asset Retirement Obligation Costs	21.6	37.2	22 years
PJM Costs and Off-system Sales Margin Sharing - Indiana	20.1	57.0	2 years
Storm-Related Costs	11.3	44.2	5 years
Virginia Transmission Rate Adjustment Clause	—	32.6	
Other Regulatory Assets Approved for Recovery	83.0	111.7	various
Total Regulatory Assets Currently Not Earning a Return	1,882.9	1,971.8	
Total Regulatory Assets Approved for Recovery	3,022.4	3,265.6	
Total Noncurrent Regulatory Assets	$ 3,310.4	$ 3,587.6	

(a) As of December 31, 2018, AEP Texas has deferred $129 million related to Hurricane Harvey and will seek securitization of the distribution related assets. See Note 4 - Rate Matters for additional information.

(b) In 2015, APCo recorded a $91 million reduction to accumulated depreciation related to the remaining net book value of plants retired in 2015, primarily in its Virginia jurisdiction. These plants were normal retirements at the end of their depreciable lives under the group composite method of depreciation. APCo's recovery of the remaining Virginia net book value for the retired plants will be considered in the Virginia SCC's 2020 triennial review of APCo's generation and distribution base rates.

	AEP		
	December 31,		Remaining
	2018	2017	Refund Period
Current Regulatory Liabilities	(in millions)		
Over-recovered Fuel Costs - pays a return	$ 35.7	$ 8.7	1 year
Over-recovered Fuel Costs - does not pay a return	22.9	3.2	1 year
Total Current Regulatory Liabilities	$ 58.6	$ 11.9	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Pending Final Regulatory Determination	$ 0.2	$ 0.2	
Total Regulatory Liabilities Currently Not Paying a Return	0.2	0.2	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	1,025.3	4,256.7	
Excess ADIT that is Not Subject to Rate Normalization Requirements	695.0	1,378.0	
Total Income Tax Related Regulatory Liabilities	1,720.3	5,634.7	
Total Regulatory Liabilities Pending Final Regulatory Determination	1,720.5	5,634.9	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	2,742.8	2,637.1	(b)
Ohio Basic Transmission Cost Rider	68.8	—	2 years
Excess Earnings	8.9	9.4	35 years
Deferred Investment Tax Credits	8.7	10.6	42 years
Advanced Metering Infrastructure Surcharge	8.5	12.7	2 years
Other Regulatory Liabilities Approved for Payment	0.4	1.3	various
Total Regulatory Liabilities Currently Paying a Return	2,838.1	2,671.1	
Regulatory Liabilities Currently Not Paying a Return			
Excess Nuclear Decommissioning Funding	828.5	945.0	(c)
Deferred Investment Tax Credits	204.9	191.2	44 years
PJM Transmission Enhancement Refund	164.2	—	7 years
Transition Charges - Texas	46.0	46.0	6 years
Unrealized Gain on Forward Commitments	45.9	15.0	6 years
Ohio Enhanced Service Reliability Plan	43.1	30.6	2 years
Spent Nuclear Fuel	42.9	43.2	(c)
Peak Demand Reduction/Energy Efficiency	17.5	25.6	3 years
Other Regulatory Liabilities Approved for Payment	84.8	41.6	various
Total Regulatory Liabilities Currently Not Paying a Return	1,477.8	1,338.2	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	2,925.7	—	(d)
Excess ADIT that is Not Subject to Rate Normalization Requirements	864.3	—	18 years
Income Taxes Subject to Flow Through	(1,286.1)	(1,221.9)	56 years
Total Income Tax Related Regulatory Liabilities	2,503.9	(1,221.9)	
Total Regulatory Liabilities Approved for Payment	6,819.8	2,787.4	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 8,540.3	$ 8,422.3	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See “Federal Tax Reform” section of Note 12 for additional information.
(b) Relieved as removal costs are incurred.
(c) Relieved when plant is decommissioned.
(d) Refunded using ARAM.

Regulatory Assets:	AEP Texas December 31, 2018	2017	Remaining Recovery Period
	(in millions)		
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs (a)	$ 152.4	$ 123.3	
Rate Case Expense	0.2	0.1	
Total Regulatory Assets Pending Final Regulatory Approval	152.6	123.4	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Advanced Metering System	45.3	33.5	2 years
Meter Replacement Costs	40.1	44.9	9 years
Total Regulatory Assets Currently Earning a Return	85.4	78.4	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	176.9	151.2	12 years
Unamortized Loss on Reacquired Debt	6.0	7.7	19 years
Transmission Cost Recovery Factor	1.7	9.5	2 years
Other Regulatory Assets Approved for Recovery	7.4	8.5	various
Total Regulatory Assets Currently Not Earning a Return	192.0	176.9	
Total Regulatory Assets Approved for Recovery	277.4	255.3	
Total Noncurrent Regulatory Assets	$ 430.0	$ 378.7	

(a) As of December 31, 2018, AEP Texas has deferred $129 million related to Hurricane Harvey and will seek securitization of the distribution related assets. See Note 4 - Rate Matters for additional information.

Regulatory Liabilities:	AEP Texas December 31, 2018	2017	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	$ 277.1	$ 578.3	
Excess ADIT that is Not Subject to Rate Normalization Requirements	141.4	103.3	
Total Regulatory Liabilities Pending Final Regulatory Determination	418.5	681.6	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	645.2	599.2	(b)
Advanced Metering Infrastructure Surcharge	8.5	12.7	2 years
Excess Earnings	6.3	6.8	13 years
Total Regulatory Liabilities Currently Paying a Return	660.0	618.7	
Regulatory Liabilities Currently Not Paying a Return			
Transition Charges - Texas	46.0	46.0	6 years
Deferred Investment Tax Credits	10.8	12.3	44 years
Other Regulatory Liabilities Approved for Payment	—	0.6	various
Total Regulatory Liabilities Currently Not Paying a Return	56.8	58.9	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	251.8	—	(c)
Income Taxes Subject to Flow Through	(42.8)	(38.7)	31 years
Total Income Tax Related Regulatory Liabilities	209.0	(38.7)	
Total Regulatory Liabilities Approved for Payment	925.8	638.9	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,344.3	$ 1,320.5	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See “Federal Tax Reform” section of Note 12 for additional information.

(b) Relieved as removal costs are incurred.

(c) Refunded using ARAM.

	AEPTCo				
	December 31,				Remaining Recovery Period
Regulatory Assets:	2018		2017		
	(in millions)				
Noncurrent Regulatory Assets					
Regulatory assets approved for recovery:					
Regulatory Assets Currently Not Earning a Return					
PJM/SPP Annual Formula Rate True Up	$	12.9	$	11.7	2 years
Total Regulatory Assets Approved for Recovery		12.9		11.7	
Total Noncurrent Regulatory Assets	$	12.9	$	11.7	

	AEPTCo				
	December 31,				Remaining Refund Period
Regulatory Liabilities:	2018		2017		
	(in millions)				
Noncurrent Regulatory Liabilities					
Regulatory liabilities pending final regulatory determination:					
Income Tax Related Regulatory Liabilities (a)					
Excess ADIT Associated with Certain Depreciable Property	$	73.9	$	512.8	
Excess ADIT that is Not Subject to Rate Normalization Requirements		4.5		(20.6)	
Total Regulatory Liabilities Pending Final Regulatory Determination		78.4		492.2	
Regulatory liabilities approved for payment:					
Regulatory Liabilities Currently Paying a Return					
Asset Removal Costs		99.5		66.7	(c)
Total Regulatory Liabilities Currently Paying a Return		99.5		66.7	
Income Tax Related Regulatory Liabilities (a)					
Excess ADIT Associated with Certain Depreciable Property		453.4		—	(d)
Excess ADIT that is Not Subject to Rate Normalization Requirements		(28.5)		—	10 years
Income Taxes Subject to Flow Through (b)		(81.5)		(65.1)	52 years
Total Income Tax Related Regulatory Liabilities		343.4		(65.1)	
Total Regulatory Liabilities Approved for Payment		442.9		1.6	
Total Noncurrent Regulatory Liabilities	$	521.3	$	493.8	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.

(b) The 2017 balance reflects the revisions made to AEPTCo's previously issued financial statements. For additional details on the revisions to AEPTCo's financial statements, see Note 1 - Significant Accounting Matters.

(c) Relieved as removal costs are incurred.

(d) Refunded using ARAM.

	APCo		
	December 31,		Remaining Recovery Period
Regulatory Assets:	2018	2017	
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs, Virginia - earns a return	$ 82.4	$ 21.4	1 year
Under-recovered Fuel Costs, West Virginia - does not earn a return	17.2	67.4	1 year
Total Current Regulatory Assets	$ 99.6	$ 88.8	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Materials and Supplies	$ 9.0	$ 9.1	
Total Regulatory Assets Currently Earning a Return	9.0	9.1	
Regulatory Assets Currently Not Earning a Return			
Plant Retirement Costs - Asset Retirement Obligation Costs	35.3	39.7	
Other Regulatory Assets Pending Final Regulatory Approval	0.6	0.6	
Total Regulatory Assets Currently Not Earning a Return	35.9	40.3	
Total Regulatory Assets Pending Final Regulatory Approval (a)	44.9	49.4	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant - West Virginia	85.3	86.3	25 years
West Virginia Delayed Customer Billing	0.6	7.8	1 year
Other Regulatory Assets Approved for Recovery	0.6	3.9	various
Total Regulatory Assets Currently Earning a Return	86.5	98.0	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	172.2	168.8	12 years
Unamortized Loss on Reacquired Debt	89.3	93.2	27 years
Vegetation Management Program - West Virginia	26.6	33.5	3 years
Peak Demand Reduction/Energy Efficiency	19.7	18.1	8 years
Postemployment Benefits	18.0	18.8	4 years
Virginia Generation Rate Adjustment Clause	10.3	7.3	2 years
Virginia Transmission Rate Adjustment Clause	—	32.6	
Storm-Related Costs - West Virginia	—	32.2	
Other Regulatory Assets Approved for Recovery	8.3	22.0	various
Total Regulatory Assets Currently Not Earning a Return	344.4	426.5	
Total Regulatory Assets Approved for Recovery	430.9	524.5	
Total Noncurrent Regulatory Assets	$ 475.8	$ 573.9	

(a) In 2015, APCo recorded a $91 million reduction to accumulated depreciation related to the remaining net book value of plants retired in 2015, primarily in its Virginia jurisdiction. These plants were normal retirements at the end of their depreciable lives under the group composite method of depreciation. APCo's recovery of the remaining Virginia net book value for the retired plants will be considered in the Virginia SCC's 2020 triennial review of APCo's generation and distribution base rates.

Regulatory Liabilities:	APCo December 31, 2018	APCo December 31, 2017	Remaining Refund Period
	(in millions)		
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	$ 268.2	$ 794.4	
Excess ADIT that is Not Subject to Rate Normalization Requirements	283.7	381.1	
Total Regulatory Liabilities Pending Final Regulatory Determination	551.9	1,175.5	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	618.3	615.8	(b)
Deferred Investment Tax Credits	1.0	0.9	42 years
Total Regulatory Liabilities Currently Paying a Return	619.3	616.7	
Regulatory Liabilities Currently Not Paying a Return			
PJM Transmission Enhancement Refund	47.7	—	7 years
Unrealized Gain on Forward Commitments	34.7	9.5	6 years
Virginia Transmission Rate Adjustment Clause	11.3	—	2 years
Consumer Rate Relief - West Virginia	8.8	6.5	1 year
Other Regulatory Liabilities Approved for Payment	3.9	1.9	various
Total Regulatory Liabilities Currently Not Paying a Return	106.4	17.9	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	453.5	—	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	84.5	—	10 years
Income Taxes Subject to Flow Through	(365.9)	(355.2)	26 years
Total Income Tax Related Regulatory Liabilities	172.1	(355.2)	
Total Regulatory Liabilities Approved for Payment	897.8	279.4	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,449.7	$ 1,454.9	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.
(b) Relieved as removal costs are incurred.
(c) Refunded using ARAM.

Regulatory Assets:	I&M December 31, 2018	I&M December 31, 2017	Remaining Recovery Period
	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return	$ —	$ 15.0	
Total Current Regulatory Assets	$ —	$ 15.0	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Not Earning a Return			
Cook Plant Uprate Project	$ —	$ 36.3	
Cook Plant Turbine	—	15.9	
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	—	14.7	
Rockport Plant Dry Sorbent Injection System - Indiana	—	10.4	
Other Regulatory Assets Pending Final Regulatory Approval	3.3	2.0	
Total Regulatory Assets Pending Final Regulatory Approval	3.3	79.3	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	232.2	245.3	10 years
Cook Plant Uprate Project	35.0	—	15 years
Deferred Cook Plant Life Cycle Management Project Costs - Michigan	16.1	—	16 years
Cook Plant Turbine	15.8	—	20 years
Rockport Plant Dry Sorbent Injection System - Indiana	11.5	—	9 years
Cook Plant, Unit 2 Baffle Bolts - Indiana	5.7	6.0	20 years
Other Regulatory Assets Approved for Recovery	2.4	1.0	various
Total Regulatory Assets Currently Earning a Return	318.7	252.3	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	84.9	77.8	12 years
Cook Plant Nuclear Refueling Outage Levelization	37.5	66.7	3 years
PJM Costs and Off-system Sales Margin Sharing - Indiana	20.1	57.0	2 years
Unamortized Loss on Reacquired Debt	18.7	9.5	30 years
Postemployment Benefits	6.5	9.7	4 years
Medicare Subsidy	6.1	7.1	6 years
Other Regulatory Assets Approved for Recovery	16.7	20.0	various
Total Regulatory Assets Currently Not Earning a Return	190.5	247.8	
Total Regulatory Assets Approved for Recovery	509.2	500.1	
Total Noncurrent Regulatory Assets	$ 512.5	$ 579.4	

Regulatory Liabilities:	I&M December 31, 2018		I&M December 31, 2017		Remaining Refund Period
	(in millions)				
Current Regulatory Liabilities					
Over-recovered Fuel Costs, Michigan - pays a return	$	4.5	$	—	1 year
Over-recovered Fuel Costs, Indiana - does not pay a return		22.9		2.7	1 year
Total Current Regulatory Liabilities	$	27.4	$	2.7	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits					
Regulatory liabilities pending final regulatory determination:					
Income Tax Related Regulatory Liabilities (a)					
Excess ADIT Associated with Certain Depreciable Property	$	125.0	$	534.6	
Excess ADIT that is Not Subject to Rate Normalization Requirements		40.6		193.0	
Total Regulatory Liabilities Pending Final Regulatory Determination		165.6		727.6	
Regulatory liabilities approved for payment:					
Regulatory Liabilities Currently Paying a Return					
Asset Removal Costs		182.5		202.2	(b)
Total Regulatory Liabilities Currently Paying a Return		182.5		202.2	
Regulatory Liabilities Currently Not Paying a Return					
Excess Nuclear Decommissioning Funding		828.5		945.0	(c)
Spent Nuclear Fuel		42.9		43.2	(c)
Deferred Investment Tax Credits		29.4		34.1	21 years
PJM Transmission Enhancement Refund		29.1		—	7 years
Other Regulatory Liabilities Approved for Payment		24.0		11.5	various
Total Regulatory Liabilities Currently Not Paying a Return		953.9		1,033.8	
Income Tax Related Regulatory Liabilities (a)					
Excess ADIT Associated with Certain Depreciable Property		362.0		—	(d)
Excess ADIT that is Not Subject to Rate Normalization Requirements		192.6		—	10 years
Income Taxes Subject to Flow Through		(282.1)		(254.9)	26 years
Total Income Tax Related Regulatory Liabilities		272.5		(254.9)	
Total Regulatory Liabilities Approved for Payment		1,408.9		981.1	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$	1,574.5	$	1,708.7	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.
(b) Relieved as removal costs are incurred.
(c) Relieved when plant is decommissioned.
(d) Refunded using ARAM.

	OPCo				
	December 31,				Remaining Recovery Period
Regulatory Assets:	2018		2017		
	(in millions)				
Current Regulatory Assets					
Under-recovered Fuel Costs - earns a return (a)	$	0.4	$	115.9	1 year
Total Current Regulatory Assets	$	0.4	$	115.9	
Noncurrent Regulatory Assets					
Regulatory assets pending final regulatory approval:					
Regulatory Assets Currently Not Earning a Return					
Other Regulatory Assets Pending Final Regulatory Approval	$	1.0	$	—	
Total Regulatory Assets Pending Final Regulatory Approval		1.0		—	
Regulatory assets approved for recovery:					
Regulatory Assets Currently Earning a Return					
Ohio Capacity Deferral		57.8		172.6	1 year
Ohio Distribution Decoupling		12.3		61.7	2 years
Ohio Basic Transmission Cost Rider		—		90.8	
Other Regulatory Assets Approved for Recovery		0.9		1.7	various
Total Regulatory Assets Currently Earning a Return		71.0		326.8	
Regulatory Assets Currently Not Earning a Return					
Pension and OPEB Funded Status		181.5		170.6	12 years
Unrealized Loss on Forward Commitments		100.2		131.8	14 years
Smart Grid Costs		8.1		—	2 years
Postemployment Benefits		7.9		7.2	4 years
Unamortized Loss on Reacquired Debt		6.5		7.8	20 years
Other Regulatory Assets Approved for Recovery		11.3		8.6	various
Total Regulatory Assets Currently Not Earning a Return		315.5		326.0	
Total Regulatory Assets Approved for Recovery		386.5		652.8	
Total Noncurrent Regulatory Assets	$	387.5	$	652.8	

(a) December 31, 2017 balance includes PIRR.

	OPCo		
	December 31,		Remaining Refund Period
Regulatory Liabilities:	2018	2017	
	(in millions)		
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Pending Final Regulatory Determination	$ 0.2	$ 0.2	
Total Regulatory Liabilities Currently Not Paying a Return	0.2	0.2	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	—	436.3	
Excess ADIT that is Not Subject to Rate Normalization Requirements	—	230.8	
Total Income Tax Related Regulatory Liabilities	—	667.1	
Total Regulatory Liabilities Pending Final Regulatory Determination	0.2	667.3	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	436.6	428.8	(b)
Ohio Basic Transmission Cost Rider	68.8	—	2 years
Other Regulatory Liabilities Approved for Payment	0.4	1.4	various
Total Regulatory Liabilities Currently Paying a Return	505.8	430.2	
Regulatory Liabilities Currently Not Paying a Return			
PJM Transmission Enhancement Refund	71.3	—	7 years
Ohio Enhanced Service Reliability Plan	43.1	30.6	2 years
Peak Demand Reduction/Energy Efficiency	14.9	23.6	2 years
Distribution Investment Rider	7.8	0.3	2 years
Other Regulatory Liabilities Approved for Payment	11.3	11.1	various
Total Regulatory Liabilities Currently Not Paying a Return	148.4	65.6	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	350.5	—	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	279.1	—	10 years
Income Taxes Subject to Flow Through	(62.8)	(62.9)	29 years
Total Income Tax Related Regulatory Liabilities	566.8	(62.9)	
Total Regulatory Liabilities Approved for Payment	1,221.0	432.9	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 1,221.2	$ 1,100.2	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.

(b) Relieved as removal costs are incurred.

(c) Refunded using ARAM.

	PSO		
	December 31,		Remaining Recovery Period
	2018	2017	
Regulatory Assets:	(in millions)		
Current Regulatory Assets			
Under-recovered Fuel Costs - earns a return	$ —	$ 36.7	
Total Current Regulatory Assets	$ —	$ 36.7	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Oklaunion Power Station Accelerated Depreciation	$ 5.5	$ —	
Total Regulatory Assets Currently Earning a Return	5.5	—	
Regulatory Assets Currently Not Earning a Return			
Other Regulatory Assets Pending Final Regulatory Approval	0.5	3.3	
Total Regulatory Assets Currently Not Earning a Return	0.5	3.3	
Total Regulatory Assets Pending Final Regulatory Approval	6.0	3.3	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs - Unrecovered Plant	153.4	138.5	22 years
Meter Replacement Costs	34.3	38.8	9 years
Storm-Related Costs	31.1	39.0	4 years
Environmental Control Projects	29.2	28.1	22 years
Red Rock Generating Facility	8.6	8.8	38 years
Other Regulatory Assets Approved for Recovery	0.5	0.5	various
Total Regulatory Assets Currently Earning a Return	257.1	253.7	
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	84.3	72.7	12 years
Peak Demand Reduction/Energy Efficiency	6.3	13.0	2 years
Unamortized Loss on Reacquired Debt	4.3	5.0	14 years
SPP Base Plan Fees	1.4	16.3	2 years
Other Regulatory Assets Approved for Recovery	9.6	4.1	various
Total Regulatory Assets Currently Not Earning a Return	105.9	111.1	
Total Regulatory Assets Approved for Recovery	363.0	364.8	
Total Noncurrent Regulatory Assets	$ 369.0	$ 368.1	

	PSO		
	December 31,		Remaining Refund Period
Regulatory Liabilities:	2018	2017	
	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs - pays a return	$ 20.1	$ —	1 year
Total Current Regulatory Liabilities	$ 20.1	$ —	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	$ —	$ 447.7	
Excess ADIT that is Not Subject to Rate Normalization Requirements	—	92.1	
Total Regulatory Liabilities Pending Final Regulatory Determination	—	539.8	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	276.8	268.8	(b)
Total Regulatory Liabilities Currently Paying a Return	276.8	268.8	
Regulatory Liabilities Currently Not Paying a Return			
Deferred Investment Tax Credits	51.5	50.7	26 years
Other Regulatory Liabilities Approved for Payment	2.5	2.3	various
Total Regulatory Liabilities Currently Not Paying a Return	54.0	53.0	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	415.2	—	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	126.4	—	10 years
Income Taxes Subject to Flow Through	(7.7)	(8.1)	27 years
Total Income Tax Related Regulatory Liabilities	533.9	(8.1)	
Total Regulatory Liabilities Approved for Payment	864.7	313.7	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 864.7	$ 853.5	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.
(b) Relieved as removal costs are incurred.
(c) Refunded using ARAM.

	SWEPCo				
	December 31,				Remaining Recovery Period
	2018		2017		
Regulatory Assets:	(in millions)				
Current Regulatory Assets					
Under-recovered Fuel Costs, Arkansas/Louisiana - earns a return	$	18.8	$	14.1	1 year
Total Current Regulatory Assets	$	18.8	$	14.1	
Noncurrent Regulatory Assets					
Regulatory assets pending final regulatory approval:					
Regulatory Assets Currently Earning a Return					
Plant Retirement Costs - Unrecovered Plant	$	50.3	$	50.3	
Other Regulatory Assets Pending Final Regulatory Approval		0.3		0.5	
Total Regulatory Assets Currently Earning a Return		50.6		50.8	
Regulatory Assets Currently Not Earning a Return					
Asset Retirement Obligation - Arkansas, Louisiana		5.3		4.0	
Rate Case Expense - Texas		4.9		4.3	
Shipe Road Transmission Project - FERC		—		3.3	
Other Regulatory Assets Pending Final Regulatory Approval		3.6		2.5	
Total Regulatory Assets Currently Not Earning a Return		13.8		14.1	
Total Regulatory Assets Pending Final Regulatory Approval		64.4		64.9	
Regulatory assets approved for recovery:					
Regulatory Assets Currently Earning a Return					
Environmental Controls Projects		14.2		—	14 years
Other Regulatory Assets Approved for Recovery		7.2		7.2	various
Total Regulatory Assets Currently Earning a Return		21.4		7.2	
Regulatory Assets Currently Not Earning a Return					
Pension and OPEB Funded Status		108.4		101.0	12 years
Plant Retirement Costs - Unrecovered Plant		17.1		17.6	23 years
Unamortized Loss on Reacquired Debt		7.4		4.7	25 years
Medicare Subsidy		3.2		3.7	6 years
Environmental Controls Projects		—		15.3	
Other Regulatory Assets Approved for Recovery		8.9		6.2	various
Total Regulatory Assets Currently Not Earning a Return		145.0		148.5	
Total Regulatory Assets Approved for Recovery		166.4		155.7	
Total Noncurrent Regulatory Assets	$	230.8	$	220.6	

	SWEPCo		
	December 31,		Remaining Refund Period
	2018	2017	
Regulatory Liabilities:	(in millions)		
Current Regulatory Liabilities			
Over-recovered Fuel Costs, Texas - pays a return	$ 11.1	$ 8.7	1 year
Total Current Regulatory Liabilities	$ 11.1	$ 8.7	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities pending final regulatory determination:			
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	$ 280.1	$ 650.5	
Excess ADIT that is Not Subject to Rate Normalization Requirements	26.9	62.7	
Total Regulatory Liabilities Pending Final Regulatory Determination	307.0	713.2	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	437.8	424.5	(b)
Other Regulatory Liabilities Approved for Payment	2.5	2.6	various
Total Regulatory Liabilities Currently Paying a Return	440.3	427.1	
Regulatory Liabilities Currently Not Paying a Return			
Deferred Investment Tax Credits	4.5	5.9	13 years
Other Regulatory Liabilities Approved for Payment	4.9	7.5	various
Total Regulatory Liabilities Currently Not Paying a Return	9.4	13.4	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	370.5	—	(c)
Excess ADIT that is Not Subject to Rate Normalization Requirements	54.3	—	2 years
Income Taxes Subject to Flow Through	(258.5)	(257.3)	31 years
Total Income Tax Related Regulatory Liabilities	166.3	(257.3)	
Total Regulatory Liabilities Approved for Payment	616.0	183.2	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 923.0	$ 896.4	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base. See "Federal Tax Reform" section of Note 12 for additional information.

(b) Relieved as removal costs are incurred.

(c) Refunded using ARAM.

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The disclosures in this note apply to all Registrants unless indicated otherwise.

The Registrants are subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Registrants business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against the Registrants cannot be predicted. Management accrues contingent liabilities only when management concludes that it is both probable that a liability has been incurred at the date of the financial statements and the amount of loss can be reasonably estimated. When management determines that it is not probable, but rather reasonably possible that a liability has been incurred at the date of the financial statements, management discloses such contingencies and the possible loss or range of loss if such estimate can be made. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent the maximum possible loss exposure. Circumstances change over time and actual results may vary significantly from estimates.

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements.

COMMITMENTS (Applies to all Registrants except AEP Texas and AEPTCo)

The AEP System has substantial commitments for fuel, energy and capacity contracts as part of the normal course of business. Certain contracts contain penalty provisions for early termination.

In accordance with the accounting guidance for "Commitments", the following tables summarize the Registrants' actual contractual commitments as of December 31, 2018:

Contractual Commitments - AEP	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 1,081.7	$ 1,020.7	$ 306.7	$ 135.0	$ 2,544.1
Energy and Capacity Purchase Contracts	239.7	463.6	324.3	1,337.2	2,364.8
Total	$ 1,321.4	$ 1,484.3	$ 631.0	$ 1,472.2	$ 4,908.9

Contractual Commitments - APCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 391.8	$ 390.1	$ 8.4	$ 0.5	$ 790.8
Energy and Capacity Purchase Contracts	37.0	72.0	74.0	317.7	500.7
Total	$ 428.8	$ 462.1	$ 82.4	$ 318.2	$ 1,291.5

Contractual Commitments - I&M	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 251.4	$ 293.1	$ 187.8	$ 83.8	$ 816.1
Energy and Capacity Purchase Contracts	126.8	264.0	166.4	322.3	879.5
Total	$ 378.2	$ 557.1	$ 354.2	$ 406.1	$ 1,695.6

Contractual Commitments - OPCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Energy and Capacity Purchase Contracts	$ 31.0	$ 59.2	$ 60.2	$ 338.6	$ 489.0

Contractual Commitments - PSO	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 58.4	$ 69.7	$ 20.1	$ —	$ 148.2
Energy and Capacity Purchase Contracts	93.0	182.2	75.3	226.2	576.7
Total	$ 151.4	$ 251.9	$ 95.4	$ 226.2	$ 724.9

Contractual Commitments - SWEPCo	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 108.8	$ 132.1	$ 32.6	$ —	$ 273.5
Energy and Capacity Purchase Contracts	33.4	62.4	50.2	125.8	271.8
Total	$ 142.2	$ 194.5	$ 82.8	$ 125.8	$ 545.3

(a) Represents contractual commitments to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.

GUARANTEES

Liabilities for guarantees are recorded in accordance with the accounting guidance for "Guarantees." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third-parties unless specified below.

Letters of Credit (Applies to AEP, AEP Texas and OPCo)

Standby letters of credit are entered into with third-parties. These letters of credit are issued in the ordinary course of business and cover items such as natural gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves.

AEP has a $4 billion revolving credit facility due in June 2022, under which up to $1.2 billion may be issued as letters of credit on behalf of subsidiaries. As of December 31, 2018, no letters of credit were issued under the revolving credit facility.

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of subsidiaries under four uncommitted facilities totaling $305 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of December 31, 2018 were as follows:

Company	Amount	Maturity
	(in millions)	
AEP	$ 60.6	January 2019 to December 2019
AEP Texas (a)	2.8	January 2019
OPCo	0.6	September 2019

(a) In January 2019, the letter of credit was amended to $2.2 million and the maturity date was extended until January 2020.

AEP has $45 million of variable rate Pollution Control Bonds supported by $46 million of bilateral letters of credit maturing in July 2019.

Guarantees of Third-Party Obligations (Applies to AEP and SWEPCo)

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of $140 million. Since SWEPCo uses self-bonding, the guarantee commits SWEPCo to complete the reclamation, in the event, Sabine does not complete the work. This guarantee ends upon depletion of reserves and completion of reclamation. The reserves are estimated to deplete in 2036 with reclamation completed by 2046 at an estimated cost of $107 million. Actual reclamation costs could vary due to inflation and

scope changes to the mine reclamation. As of December 31, 2018, SWEPCo has collected $75 million through a rider for reclamation costs, of which $80 million was recorded in Asset Retirement Obligations, offset by $5 million recorded in Deferred Charges and Other Noncurrent Assets on SWEPCo's balance sheets.

Sabine charges all of its costs to its only customer, SWEPCo, which recovers these costs through its fuel clauses.

Guarantees of Equity Method Investees (Applies to AEP)

In December 2016, AEP issued a performance guarantee for a 50% owned joint venture which is accounted for as an equity method investment. If the joint venture were to default on payments or performance, AEP would be required to make payments on behalf of the joint venture. As of December 31, 2018, the maximum potential amount of future payments associated with this guarantee was $75 million, which expires in December 2019.

Indemnifications and Other Guarantees

Contracts

The Registrants enter into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of December 31, 2018, there were no material liabilities recorded for any indemnifications.

AEPSC conducts power purchase and sale activity on behalf of APCo, I&M, KPCo and WPCo, who are jointly and severally liable for activity conducted on their behalf. AEPSC also conducts power purchase and sale activity on behalf of PSO and SWEPCo, who are jointly and severally liable for activity conducted on their behalf.

Lease Obligations

Certain Registrants lease equipment under master lease agreements. See “Master Lease Agreements”, “Railcar Lease” and “AEPRO Boat and Barge Leases” sections of Note 13 for additional information.

ENVIRONMENTAL CONTINGENCIES (Applies to All Registrants except AEPTCo)

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, the generation plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and non-hazardous materials. The Registrants currently incur costs to dispose of these substances safely.

Superfund addresses clean-up of hazardous substances that are released to the environment. The Federal EPA administers the clean-up programs. Several states enacted similar laws. As of December 31, 2018, APCo and OPCo are named as a Potentially Responsible Party (PRP) for one and three sites, respectively, by the Federal EPA for which alleged liability is unresolved. There are 11 additional sites for which APCo, I&M, KPCo, OPCo and SWEPCo received information requests which could lead to PRP designation. I&M has also been named potentially liable at two sites under state law including the site discussed in the next paragraph. In those instances where a PRP or defendant has been named, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

In 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. The remediation work was completed in 2018 in accordance with a plan approved by MDEQ with no significant effects on net income.

Management evaluates the potential liability for each Superfund site separately, but several general statements can be made about potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often non-hazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. As of December 31, 2018, management's estimates do not anticipate material clean-up costs for identified Superfund sites.

NUCLEAR CONTINGENCIES (APPLIES TO AEP AND I&M)

I&M owns and operates the two-unit 2,278 MW Cook Plant under licenses granted by the NRC. I&M has a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generation units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial.

Decommissioning and Low-Level Waste Accumulation Disposal

The costs to decommission a nuclear plant are affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of Cook Plant. The most recent decommissioning cost study was performed in 2018. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste was $2 billion in 2018 non-discounted dollars, with additional ongoing costs of $6 million per year for post decommissioning storage of SNF and an eventual cost of $37 million for the subsequent decommissioning of the SNF storage facility, also in 2018 non-discounted dollars. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amounts recovered in rates were $8 million, $9 million and $9 million for the years ended December 31, 2018, 2017 and 2016, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2018 and 2017, the total decommissioning trust fund balances were $2.2 billion and $2.2 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. The decommissioning costs (including unrealized gains and losses, interest and trust funds expenses) increase or decrease the recorded liability.

I&M continues to work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. However, future net income and cash flows would be reduced and financial condition could be impacted if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

Spent Nuclear Fuel Disposal

The federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one-mill per KWh for fuel consumed after April 6, 1983 at the Cook Plant was collected from customers and remitted to the DOE through May 14, 2014. In May 2014, pursuant to court order from the U.S Court of Appeals for the District of Columbia Circuit, the DOE adjusted the fee to $0. As of December 31, 2018 and 2017, fees and related interest of $274 million and $269 million, respectively, for fuel consumed prior to April 7, 1983 were recorded as Long-term Debt and funds collected from customers along with related earnings totaling $317 million and $312 million, respectively, to pay the fee were recorded as part of Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

In 2011, I&M signed a settlement agreement with the federal government which permits I&M to make annual filings to recover certain SNF storage costs incurred as a result of the government's delay in accepting SNF for permanent storage. Under the settlement agreement, I&M received $11 million, $22 million and $6 million in 2018, 2017 and 2016, respectively, to recover costs and will be eligible to receive additional payment of annual claims for allowed costs that are incurred through December 31, 2019. The proceeds reduced costs for dry cask storage. As of December

31, 2018 and 2017, I&M deferred $8 million and $11 million, respectively, in Prepayments and Other Current Assets and $23 million and $5 million, respectively, in Deferred Charges and Other Noncurrent Assets on the balance sheets for dry cask storage and related operation and maintenance costs for recovery under this agreement. See “Fair Value Measurements of Trust Assets for Decommissioning and Spent Nuclear Fuel Disposal” section of Note 11 for additional information.

Nuclear Insurance

I&M carries nuclear property insurance of $2.7 billion to cover an incident at Cook Plant including coverage for decontamination and stabilization, as well as premature decommissioning caused by an extraordinary incident. Insurance coverage for a nonnuclear property incident at Cook Plant is $1.5 billion. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes industry mutual insurers for the placement of this insurance coverage. Coverage from these industry mutual insurance programs require a contingent financial obligation of up to $50 million for I&M, which is assessable if the insurer’s financial resources would be inadequate to pay for industry losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public nuclear liability arising from a nuclear incident of $14.1 billion and applies to any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $450 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $276 million per nuclear incident on Cook Plant’s reactors payable in annual installments of $41 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, I&M is covered for public nuclear liability for the first $450 million through commercially available insurance. The next level of liability coverage of up to $13.6 billion would be covered by claim premium assessments made under the Price-Anderson Act. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds, I&M would seek recovery of those amounts from customers through a rate increase. If recovery from customers is not possible, it could reduce future net income and cash flows and impact financial condition.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

The Registrants maintain insurance coverage normal and customary for electric utilities, subject to various deductibles. The Registrants also maintain property and casualty insurance that may cover certain physical damage or third-party injuries caused by cyber security incidents. Insurance coverage includes all risks of physical loss or damage to nonnuclear assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. The insurance programs also generally provide coverage against loss arising from certain claims made by third-parties and are in excess of retentions absorbed by the Registrants. Coverage is generally provided by a combination of the protected cell of EIS and/or various industry mutual and/or commercial insurance carriers. See “Nuclear Contingencies” section above for additional information.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to a cyber security incident or damage to the Cook Plant and costs of replacement power in the event of an incident at the Cook Plant. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could reduce future net income and cash flows and impact financial condition.

Rockport Plant Litigation (Applies to AEP and I&M)

In July 2013, the Wilmington Trust Company filed a complaint in the U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it would be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering, refueling or retirement of the unit. The plaintiffs seek a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiffs. The New York court granted a motion to transfer this case to the U.S. District Court for the Southern District of Ohio.

AEGCo and I&M sought and were granted dismissal of certain of the plaintiffs' claims, including claims for compensatory damages, breach of contract, breach of the implied covenant of good faith and fair dealing and indemnification of costs. Plaintiffs voluntarily dismissed the surviving claims that AEGCo and I&M failed to exercise prudent utility practices with prejudice, and the court issued a final judgment. The plaintiffs subsequently filed an appeal in the U.S. Court of Appeals for the Sixth Circuit.

The U.S. Court of Appeals for the Sixth Circuit issued an opinion and judgment affirming the district court's dismissal of the owners' breach of good faith and fair dealing claim as duplicative of the breach of contract claims, reversing the district court's dismissal of the breach of contract claims, and remanding the case for further proceedings.

In July 2017, AEP filed a motion with the U.S. District Court for the Southern District of Ohio in the original NSR litigation, seeking to modify the consent decree to eliminate the obligation to install certain future controls at Rockport Plant, Unit 2 if AEP does not acquire ownership of that Unit, and to modify the consent decree in other respects to preserve the environmental benefits of the consent decree. Responsive and supplemental filings have been made by all parties. In November 2017, the district court granted the owners' unopposed motion to stay the lease litigation to afford time for resolution of AEP's motion to modify the consent decree. In September 2018, the district court granted AEP's unopposed motion to stay further proceedings regarding the consent decree to facilitate settlement discussions among the parties to the consent decree. See "Proposed Modification of the NSR Litigation Consent Decree" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information.

Management will continue to defend against the claims. Given that the district court dismissed plaintiffs' claims seeking compensatory relief as premature, and that plaintiffs have yet to present a methodology for determining or any analysis supporting any alleged damages, management is unable to determine a range of potential losses that are reasonably possible of occurring.

7. DISPOSITIONS AND IMPAIRMENTS

The disclosures in this note apply to AEP unless indicated otherwise.

DISPOSITIONS

2017

Zimmer Plant (Generation & Marketing Segment)

In February 2017, AEP signed an agreement to sell its 25.4% ownership share of Zimmer Plant to a nonaffiliated party. The transaction closed in the second quarter of 2017 and did not have a material impact on net income, cash flows or financial condition. The Income before Income Tax Expense and Equity Earnings of Zimmer Plant was immaterial for the years ended December 31, 2017 and 2016.

Gavin, Waterford, Darby and Lawrenceburg Plants (Generation & Marketing Segment)

In September 2016, AEP signed a Purchase and Sale Agreement to sell AGR's Gavin, Waterford and Darby Plants as well as AEGCo's Lawrenceburg Plant totaling 5,329 MWs of competitive generation assets to a nonaffiliated party. The sale closed in January 2017 for $2.2 billion, which was recorded in Investing Activities on the statements of cash flows. The net proceeds from the transaction were $1.2 billion in cash after taxes, repayment of debt associated with these assets including a make whole payment related to the debt, payment of a coal contract associated with one of the plants and transaction fees. The sale resulted in a pretax gain of $226 million that was recorded in Gain on Sale of Merchant Generation Assets on AEP's statements of income for the year ended December 31, 2017.

2016

Tanners Creek Plant (Vertically Integrated Utilities Segment) (Applies to AEP and I&M)

In October 2016, I&M sold its retired Tanners Creek Plant site including its associated AROs to a nonaffiliated party. I&M paid $92 million and the nonaffiliated party took ownership of the Tanners Creek plant site assets and assumed responsibility for environmental liabilities and AROs, including ash pond closure, asbestos abatement and decommissioning and demolition. I&M did not record a gain or loss related to this sale. In 2018, the MPSC and IURC approved the recovery of the additional costs associated with the sale of Tanners Creek Plant over the remaining useful life of Rockport, Unit 1. If any of the costs associated with Tanners Creek are not recoverable, it could reduce future net income and impact financial condition.

Wind Farms (Applies to AEP Texas)

In December 2016, TCC and TNC merged into AEP Utilities, Inc. Prior to the merger, AEP Utilities, Inc. was a subsidiary of AEP and holding company for TCC, TNC and CSW Energy, Inc. CSW Energy, Inc. owns Desert Sky and Trent (collectively "Wind Farms"). Upon merger, AEP Utilities, Inc. changed its name to AEP Texas. Subsequent to the merger, AEP Texas exited the merchant generation business by transferring all of the common stock of the Wind Farms to a competitive AEP affiliate. No gain or loss was recognized and no cash was exchanged related to the disposition of the Wind Farms.

In the fourth quarter of 2016, the Wind Farms were determined to be discontinued operations. Accordingly, results of operations of the Wind Farms have been classified as discontinued operations on AEP Texas' statements of income for the year ended December 31, 2016 as shown in the following table:

	Year Ended December 31, 2016	
	(in millions)	
Revenue	$	18.2
Other Operation Expense		6.5
Maintenance Expense		3.4
Asset Impairment and Other Related Charges		72.7
Depreciation and Amortization Expense		9.8
Taxes Other Than Income Taxes		1.3
Total Expenses		93.7
Other Income (Expense)		(0.8)
Pretax Loss of Discontinued Operations		(76.3)
Income Tax Benefit		(27.5)
Total Loss on Discontinued Operations as Presented on the Statements of Income	$	(48.8)

IMPAIRMENTS

2018

Other Assets (Corporate and Other) (Vertically Integrated Utilities Segment) (Applies to AEP and APCo)

In the first quarter of 2018, AEP was notified by an equity investee that it had ceased operations. AEP recorded a pretax impairment of $21 million in Other Operation on the statements of income related to the equity investment and related assets. The impairment also had an immaterial impact to APCo.

Merchant Generating Assets (Generation & Marketing Segment)

A project to reconstruct a defective dam structure at Racine began in the first quarter of 2017 and reconstruction activities continued throughout 2018. An initial impairment recorded related to Racine is discussed in the "2017" section below.

As of September 30, 2018, the Racine reconstruction project had accumulated new capital expenditures of $35 million. Due to a significant increase in estimated costs to complete the reconstruction project, in the third quarter of 2018, an impairment analysis was performed. AEP performed step one of the impairment analysis using undiscounted cash flows for the estimated useful life of Racine based upon energy and capacity price curves, which were developed internally with observable Level 2 third party quotations and unobservable Level 3 inputs, as well as management's forecasts of operating expenses and capital expenditures. AEP performed step two of the impairment analysis on Racine using a ten-year discounted cash flow model based upon similar forecasted information used in the step one test. The step two analysis resulted in a determination that the fair value of Racine in its condition as of September 30, 2018 was $0. As a result, AEP recorded a pretax impairment of $35 million in Other Operation on the statements of income in the third quarter of 2018. In October 2018, AEP received authorization from the FERC to restart generation at Racine and generation resumed in November 2018.

2017

Merchant Generating Assets (Generation & Marketing Segment)

In 2017, AEP recorded an additional pretax impairment of $4 million in Asset Impairments and Other Related Charges on AEP's statements of income related to Cardinal, Unit 1, a 43.5% interest in Conesville, Unit 4, Conesville, Units 5 and 6, a 26% interest in Stuart, Units 1-4, a 25.4% interest in Zimmer, Unit 1, and a 54.7% interest in Oklaunion (collectively the "Merchant Coal-Fired Generation Assets"). The initial impairment recorded related to these assets is discussed in the "2016" section below. In addition, AEP recorded a $7 million pretax impairment as Asset Impairments and Other Related Charges on AEP's statements of income related to the sale of Zimmer Plant. The sale is further discussed in the "Disposition" section of this note.

Due to a significant increase in estimated costs identified in December 2017 to repair a defective dam structure at Racine, AEP performed an impairment analysis on Racine in accordance with accounting guidance for impairments of long-lived assets. AEP performed step one of the impairment analysis using undiscounted cash flows for the estimated useful life of Racine based upon energy and capacity price curves, which were developed internally with both observable Level 2 third party quotations and unobservable Level 3 inputs, as well as management's forecasts of operating expenses and capital expenditures. AEP performed step two of the impairment analysis on Racine using a ten-year discounted cash flow model based upon similar forecasted information used in the step one test. The step two analysis resulted in a fair value determination for Racine of $0 and AEP recorded a pretax impairment of $43 million in Assets Impairments and Other Related Charges on the statements of income in the fourth quarter of 2017.

Welsh Plant, Unit 2 and Turk Plant (Vertically Integrated Utilities Segment) (Applies to AEP and SWEPCo)

In December 2017, SWEPCo recorded a pretax impairment of $19 million in Asset Impairments and Other Related Charges on the statements of income related to the Texas jurisdictional share of Welsh Plant, Unit 2 and other disallowed plant investments. Additionally in December 2017, SWEPCo recorded a pretax impairment of $15 million in Asset Impairments and Other Related Charges on the statements of income related to the Louisiana jurisdictional share of the Turk Plant. See the "2016 Texas Base Rate Case" section of Note 4.

2016

Merchant Generating Assets (Generation & Marketing Segment)

In September 2016, due to AEP's ongoing evaluation of strategic alternatives for its merchant generation assets, declining forecasts of future energy and capacity prices, and a decreasing likelihood of cost recovery through regulatory proceedings or legislation in the state of Ohio providing for the recovery of AEP's existing Ohio merchant generation assets, AEP performed an impairment analysis at the unit level on the remaining merchant generation assets in accordance with accounting guidance for impairments of long-lived assets. The Merchant Coal-Fired Generation Assets were subject to this analysis. Additionally, Racine, Putnam and I&M's Price River coal reserves ("Coal Reserves") and the Wind Farms were also included in this analysis. For the Merchant Coal-Fired Generation Assets, Racine and the Wind Farms, AEP performed step one of the impairment analysis using undiscounted cash flows for the estimated useful lives of the assets based upon energy and capacity price curves, as applicable, which were developed internally with both observable Level 2 third party quotations and unobservable Level 3 inputs, as well as management's forecasts of operating expenses and capital expenditures. The step one analysis concluded the book value of Racine would be recovered and the book value of the remaining assets would not be recovered.

AEP performed step two of the impairment analysis on the Merchant Coal-Fired Generation Assets using a ten-year discounted cash flow model based upon forecasted energy and capacity price curves, which were developed internally using both observable Level 2 third party quotations and unobservable Level 3 inputs, as well as management's forecasts of operating expenses and capital expenditures. The step two analysis resulted in projected negative cash flows. Based on this result, coupled with the significant capital investments necessary to comply with environmental rules to allow the Merchant Coal-Fired Generation Assets to operate to the end of their currently estimated depreciable lives and the

joint-ownership structure of these facilities, management determined the fair value of these assets was $0. AEP performed step two of the impairment analysis on the Wind Farms using a ten-year discounted cash flow model utilizing forecasted energy price curves, which were developed internally using both observable Level 2 third party quotations and unobservable Level 3 inputs, as well as management's forecasts of operating expenses and capital expenditures. The results concluded the Wind Farms were also impaired.

For the Coal Reserves, AEP performed step one of the impairment analysis and concluded the book value of the assets would not be recovered. Step two of the impairment analysis on the Coal Reserves was performed using a market approach with Level 3 unobservable inputs. The results concluded the Coal Reserves were also impaired.

Based on the impairment analysis performed, in the third quarter of 2016, AEP recorded a pretax impairment of $2.3 billion in Asset Impairments and Other Related Charges on the statements of income. See the table below for additional information.

Impaired Assets	Book Value	Fair Value	Impairment
		(in millions)	
Merchant Coal-Fired Generation Assets	$ 2,139.4	$ —	$ 2,139.4
Desert Sky and Trent	118.7	46.0	72.7
Coal Reserves (a)	56.6	3.8	52.8
Total	$ 2,314.7	$ 49.8	$ 2,264.9

(a) Includes the $11 million book value of I&M's Price River Coal Reserves which were fully impaired. This $11 million impairment is reflected in the Vertically Integrated Utilities Segment.

Based on capital expenditure activity of the Merchant Coal-fired Generation Assets in the fourth quarter of 2016, AEP recorded a pretax impairment of an additional $3 million in Asset Impairments and Other Related Charges on AEP's statements of income.

8. BENEFIT PLANS

The disclosures in this note apply to all Registrants except AEPTCo unless indicated otherwise.

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see “Fair Value Measurements of Assets and Liabilities” and “Investments Held in Trust for Future Liabilities” sections of Note 1.

AEP sponsors a qualified pension plan and two unfunded nonqualified pension plans. Substantially all AEP employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. AEP also sponsors OPEB plans to provide health and life insurance benefits for retired employees.

Due to the Registrant Subsidiaries’ participation in AEP’s benefits plans, the assumptions used by the actuary, with the exception of the rate of compensation increase, and the accounting for the plans by each subsidiary are the same. This section details the assumptions that apply to all Registrants and the rate of compensation increase for each Registrant.

The Registrants recognize the funded status associated with defined benefit pension and OPEB plans on the balance sheets. Disclosures about the plans are required by the “Compensation – Retirement Benefits” accounting guidance. The Registrants recognize an asset for a plan’s overfunded status or a liability for a plan’s underfunded status, and recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. The Registrants record a regulatory asset instead of other comprehensive income for qualifying benefit costs of regulated operations that for ratemaking purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions used in the measurement of the Registrants’ benefit obligations are shown in the following tables:

	Pension Plans		OPEB	
	December 31,			
Assumption	**2018**	**2017**	**2018**	**2017**
Discount Rate	4.30%	3.65%	4.30%	3.60%
Interest Crediting Rate	4.00%	4.00%	NA	NA

NA Not applicable.

	Pension Plans	
	December 31,	
Assumption – Rate of Compensation Increase (a)	**2018**	**2017**
AEP	4.85%	4.80%
AEP Texas	4.95%	4.90%
APCo	4.75%	4.60%
I&M	4.90%	4.85%
OPCo	5.00%	4.95%
PSO	4.90%	4.90%
SWEPCo	4.85%	4.80%

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

A duration-based method is used to determine the discount rate for the plans. A hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan. The discount rate is the same for each Registrant.

For 2018, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 12% per year, with the average increase shown in the table above. The compensation increase rates reflect variations in each Registrants' population participating in the pension plan.

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions used in the measurement of each Registrants' benefit costs are shown in the following tables:

	Pension Plans			OPEB		
	Year Ended December 31,					
Assumption	**2018**	**2017**	**2016**	**2018**	**2017**	**2016**
Discount Rate	3.65%	4.05%	4.30%	3.60%	4.10%	4.30%
Interest Crediting Rate	4.00%	4.00%	4.00%	NA	NA	NA
Expected Return on Plan Assets	6.00%	6.00%	6.00%	6.00%	6.75%	7.00%

NA Not applicable.

	Pension Plans		
	Year Ended December 31,		
Assumption – Rate of Compensation Increase (a)	**2018**	**2017**	**2016**
AEP	4.85%	4.80%	4.75%
AEP Texas	4.95%	4.90%	4.85%
APCo	4.75%	4.60%	4.55%
I&M	4.90%	4.85%	4.80%
OPCo	5.00%	4.95%	4.85%
PSO	4.90%	4.90%	4.90%
SWEPCo	4.85%	4.80%	4.75%

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

The expected return on plan assets was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation, third party forecasts and current prospects for economic growth. The expected return on plan assets is the same for each Registrant.

The health care trend rate assumptions used for OPEB plans measurement purposes are shown below:

	December 31,	
Health Care Trend Rates	**2018**	**2017**
Initial	6.25%	6.50%
Ultimate	5.00%	5.00%
Year Ultimate Reached	2024	2024

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. Management monitors the plans to control security diversification and ensure compliance with the investment policy. As of December 31, 2018, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets, Funded Status and Amounts Recognized on the Balance Sheets

For the year ended December 31, 2018, the pension and OPEB plans had an actuarial gain due to an increase in the discount rate as well as updated estimates for future medical expenses in the OPEB plans. For the year ended December 31, 2017, the pension plans had an actuarial loss due to a decrease in the discount rate. The OPEB plans had an actuarial gain primarily due to a change in medical benefits for retirees which was partially offset by a decrease in the discount rate. The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets, funded status and the presentation on the balance sheets. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

AEP	**Pension Plans**		**OPEB**	
	2018	**2017**	**2018**	**2017**
Change in Benefit Obligation	**(in millions)**			
Benefit Obligation as of January 1,	$ 5,215.8	$ 5,085.8	$ 1,332.0	$ 1,447.4
Service Cost	97.6	96.5	11.6	11.2
Interest Cost	187.8	203.1	47.4	59.3
Actuarial (Gain) Loss	(306.3)	182.4	(100.1)	(97.5)
Benefit Payments	(384.6)	(352.0)	(133.6)	(128.6)
Participant Contributions	—	—	36.5	39.5
Medicare Subsidy	—	—	0.7	0.7
Benefit Obligation as of December 31,	$ 4,810.3	$ 5,215.8	$ 1,194.5	$ 1,332.0
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 5,174.1	$ 4,827.3	$ 1,732.5	$ 1,545.9
Actual Gain (Loss) on Plan Assets	(104.9)	600.0	(118.3)	271.6
Company Contributions (a)	11.3	98.8	17.1	4.1
Participant Contributions	—	—	36.5	39.5
Benefit Payments	(384.6)	(352.0)	(133.6)	(128.6)
Fair Value of Plan Assets as of December 31,	$ 4,695.9	$ 5,174.1	$ 1,534.2	$ 1,732.5
Funded (Underfunded) Status as of December 31,	$ (114.4)	$ (41.7)	$ 339.7	$ 400.5

(a) Contributions to the qualified pension plan were $0 and $93 million for the years ended December 31, 2018 and 2017, respectively. Contributions to the nonqualified pension plans were $11 million and $6 million for the years ended December 31, 2018 and 2017, respectively.

AEP	Pension Plans 2018	Pension Plans 2017	OPEB 2018	OPEB 2017
	December 31,			
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ 36.3	$ 392.2	$ 463.0
Other Current Liabilities – Accrued Short-term Benefit Liability	(5.7)	(6.2)	(2.8)	(3.2)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(108.7)	(71.8)	(49.7)	(59.3)
Funded (Underfunded) Status	$ (114.4)	$ (41.7)	$ 339.7	$ 400.5

AEP Texas	Pension Plans 2018	Pension Plans 2017	OPEB 2018	OPEB 2017
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 441.3	$ 421.7	$ 107.1	$ 120.4
Service Cost	9.2	8.6	0.9	0.9
Interest Cost	16.0	17.1	3.8	4.9
Actuarial (Gain) Loss	(20.9)	25.6	(8.3)	(11.9)
Benefit Payments	(36.3)	(31.7)	(10.7)	(10.8)
Participant Contributions	—	—	3.1	3.6
Benefit Obligation as of December 31,	$ 409.3	$ 441.3	$ 95.9	$ 107.1
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 455.9	$ 416.6	$ 147.3	$ 134.1
Actual Gain (Loss) on Plan Assets	(9.3)	61.8	(14.6)	20.4
Company Contributions	0.4	9.2	4.8	—
Participant Contributions	—	—	3.1	3.6
Benefit Payments	(36.3)	(31.7)	(10.7)	(10.8)
Fair Value of Plan Assets as of December 31,	$ 410.7	$ 455.9	$ 129.9	$ 147.3
Funded Status as of December 31,	$ 1.4	$ 14.6	$ 34.0	$ 40.2

AEP Texas	Pension Plans 2018	Pension Plans 2017	OPEB 2018	OPEB 2017
	December 31,			
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ 5.2	$ 18.6	$ 34.0	$ 40.2
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.4)	(0.4)	—	—
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(3.4)	(3.6)	—	—
Funded Status	$ 1.4	$ 14.6	$ 34.0	$ 40.2

APCo	Pension Plans		OPEB	
	2018	2017	2018	2017
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 665.0	$ 654.0	$ 236.5	$ 255.6
Service Cost	9.3	9.4	1.1	1.1
Interest Cost	23.5	25.7	8.2	10.6
Actuarial (Gain) Loss	(49.2)	15.7	(21.9)	(13.4)
Benefit Payments	(45.5)	(39.8)	(24.7)	(24.3)
Participant Contributions	—	—	6.1	6.7
Medicare Subsidy	—	—	0.2	0.2
Benefit Obligation as of December 31,	$ 603.1	$ 665.0	$ 205.5	$ 236.5
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 651.7	$ 606.4	$ 273.4	$ 246.9
Actual Gain (Loss) on Plan Assets	(12.9)	74.9	(18.7)	41.6
Company Contributions	—	10.2	2.3	2.5
Participant Contributions	—	—	6.1	6.7
Benefit Payments	(45.5)	(39.8)	(24.7)	(24.3)
Fair Value of Plan Assets as of December 31,	$ 593.3	$ 651.7	$ 238.4	$ 273.4
Funded (Underfunded) Status as of December 31,	$ (9.8)	$ (13.3)	$ 32.9	$ 36.9

	Pension Plans		OPEB	
	December 31,			
APCo	2018	2017	2018	2017
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ —	$ 62.3	$ 74.6
Other Current Liabilities – Accrued Short-term Benefit Liability	—	—	(2.1)	(2.5)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(9.8)	(13.3)	(27.3)	(35.2)
Funded (Underfunded) Status	$ (9.8)	$ (13.3)	$ 32.9	$ 36.9

I&M	Pension Plans		OPEB	
	2018	2017	2018	2017
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 624.3	$ 611.6	$ 153.5	$ 167.6
Service Cost	13.6	14.0	1.6	1.6
Interest Cost	22.1	24.3	5.4	6.9
Actuarial (Gain) Loss	(53.9)	10.8	(10.6)	(12.0)
Benefit Payments	(39.1)	(36.4)	(16.2)	(15.6)
Participant Contributions	—	—	4.5	4.9
Medicare Subsidy	—	—	0.1	0.1
Benefit Obligation as of December 31,	$ 567.0	$ 624.3	$ 138.3	$ 153.5
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 636.7	$ 586.1	$ 211.1	$ 186.6
Actual Gain (Loss) on Plan Assets	(13.8)	74.0	(12.1)	35.2
Company Contributions	—	13.0	—	—
Participant Contributions	—	—	4.5	4.9
Benefit Payments	(39.1)	(36.4)	(16.2)	(15.6)
Fair Value of Plan Assets as of December 31,	$ 583.8	$ 636.7	$ 187.3	$ 211.1
Funded Status as of December 31,	$ 16.8	$ 12.4	$ 49.0	$ 57.6

I&M	Pension Plans		OPEB	
	December 31,			
	2018	2017	2018	2017
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ 18.0	$ 13.4	$ 49.0	$ 57.6
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(1.2)	(1.0)	—	—
Funded Status	$ 16.8	$ 12.4	$ 49.0	$ 57.6

OPCo	Pension Plans		OPEB	
	2018	2017	2018	2017
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 501.1	$ 492.9	$ 144.3	$ 164.0
Service Cost	7.7	7.5	0.9	0.9
Interest Cost	17.7	19.4	5.1	6.7
Actuarial (Gain) Loss	(36.6)	13.1	(9.4)	(16.6)
Benefit Payments	(36.0)	(31.8)	(15.8)	(15.5)
Participant Contributions	—	—	4.3	4.7
Medicare Subsidy	—	—	0.1	0.1
Benefit Obligation as of December 31,	$ 453.9	$ 501.1	$ 129.5	$ 144.3
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 509.1	$ 473.8	$ 198.5	$ 182.6
Actual Gain (Loss) on Plan Assets	(7.0)	58.9	(11.6)	26.7
Company Contributions	—	8.2	—	—
Participant Contributions	—	—	4.3	4.7
Benefit Payments	(36.0)	(31.8)	(15.8)	(15.5)
Fair Value of Plan Assets as of December 31,	$ 466.1	$ 509.1	$ 175.4	$ 198.5
Funded Status as of December 31,	$ 12.2	$ 8.0	$ 45.9	$ 54.2

OPCo	Pension Plans		OPEB	
	December 31,			
	2018	2017	2018	2017
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ 12.6	$ 8.4	$ 45.9	$ 54.2
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(0.4)	(0.4)	—	—
Funded Status	$ 12.2	$ 8.0	$ 45.9	$ 54.2

PSO	Pension Plans		OPEB	
	2018	2017	2018	2017
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 276.6	$ 266.7	$ 69.4	$ 77.6
Service Cost	7.0	6.4	0.7	0.7
Interest Cost	9.9	10.7	2.5	3.2
Actuarial (Gain) Loss	(18.9)	10.1	(5.6)	(7.5)
Benefit Payments	(20.8)	(17.3)	(6.7)	(6.9)
Participant Contributions	—	—	2.0	2.3
Benefit Obligation as of December 31,	$ 253.8	$ 276.6	$ 62.3	$ 69.4
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 287.8	$ 266.0	$ 95.5	$ 86.4
Actual Gain (Loss) on Plan Assets	(5.9)	33.6	(9.2)	13.7
Company Contributions	0.1	5.5	2.7	—
Participant Contributions	—	—	2.0	2.3
Benefit Payments	(20.8)	(17.3)	(6.7)	(6.9)
Fair Value of Plan Assets as of December 31,	$ 261.2	$ 287.8	$ 84.3	$ 95.5
Funded Status as of December 31,	$ 7.4	$ 11.2	$ 22.0	$ 26.1

PSO	Pension Plans		OPEB	
	December 31,			
	2018	2017	2018	2017
	(in millions)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ 9.7	$ 13.9	$ 22.0	$ 26.1
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.2)	(0.2)	—	—
Deferred Credits and Other Noncurrent Liabilities – Accrued Long-term Benefit Liability	(2.1)	(2.5)	—	—
Funded Status	$ 7.4	$ 11.2	$ 22.0	$ 26.1

SWEPCo	Pension Plans		OPEB	
	2018	2017	2018	2017
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 314.6	$ 296.6	$ 80.3	$ 86.9
Service Cost	9.3	8.7	0.9	0.9
Interest Cost	11.3	12.3	2.8	3.6
Actuarial (Gain) Loss	(19.2)	16.3	(5.9)	(6.2)
Benefit Payments	(24.6)	(19.3)	(7.7)	(7.4)
Participant Contributions	—	—	2.3	2.5
Benefit Obligation as of December 31,	$ 291.4	$ 314.6	$ 72.7	$ 80.3
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 311.7	$ 287.3	$ 110.4	$ 96.8
Actual Gain (Loss) on Plan Assets	(7.3)	34.6	(9.2)	18.5
Company Contributions	1.2	9.1	2.7	—
Participant Contributions	—	—	2.3	2.5
Benefit Payments	(24.6)	(19.3)	(7.7)	(7.4)
Fair Value of Plan Assets as of December 31,	$ 281.0	$ 311.7	$ 98.5	$ 110.4
Funded (Underfunded) Status as of December 31,	$ (10.4)	$ (2.9)	$ 25.8	$ 30.1

	Pension Plans		OPEB	
	December 31,			
SWEPCo	2018	2017	2018	2017
	(in millions)			
Deferred Charges and Other Noncurrent Assets – Prepaid Benefit Costs	$ —	$ —	$ 25.8	$ 30.1
Other Current Liabilities – Accrued Short-term Benefit Liability	(0.2)	(0.2)	—	—
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(10.2)	(2.7)	—	—
Funded (Underfunded) Status	$ (10.4)	$ (2.9)	$ 25.8	$ 30.1

Amounts Included in Regulatory Assets, Deferred Income Taxes, AOCI and Income Tax Expense

The following tables show the components of the plans included in Regulatory Assets, Deferred Income Taxes, AOCI and Income Tax Expense and the items attributable to the change in these components:

AEP	Pension Plans		OPEB	
	December 31,			
	2018	2017	2018	2017
Components	(in millions)			
Net Actuarial Loss	$ 1,355.2	$ 1,354.2	$ 419.8	$ 309.9
Prior Service Credit	—	—	(347.2)	(416.3)
Recorded as				
Regulatory Assets	$ 1,267.9	$ 1,271.3	$ 52.5	$ (82.4)
Deferred Income Taxes	18.4	17.4	4.2	(5.0)
Net of Tax AOCI	68.9	53.9	15.9	(15.6)
Income Tax Expense (a)	—	11.6	—	(3.4)

AEP	Pension Plans		OPEB	
	2018	2017	2018	2017
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ 88.8	$ (132.8)	$ 120.4	$ (267.8)
Amortization of Actuarial Loss	(87.8)	(82.8)	(10.5)	(36.7)
Amortization of Prior Service Credit (Cost)	—	(1.0)	69.1	69.1
Change for the Year Ended December 31,	$ 1.0	$ (216.6)	$ 179.0	$ (235.4)

AEP Texas	Pension Plans		OPEB	
	December 31,			
	2018	2017	2018	2017
Components	(in millions)			
Net Actuarial Loss	$ 182.0	$ 175.2	$ 38.0	$ 23.9
Prior Service Credit	—	—	(29.5)	(35.4)
Recorded as				
Regulatory Assets	$ 168.2	$ 161.4	$ 8.7	$ (10.2)
Deferred Income Taxes	2.9	2.9	—	(0.3)
Net of Tax AOCI	10.9	8.9	(0.2)	(0.8)
Income Tax Expense (a)	—	2.0	—	(0.2)

AEP Texas	Pension Plans		OPEB	
	2018	2017	2018	2017
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ 14.0	$ (11.1)	$ 14.9	$ (23.6)
Amortization of Actuarial Loss	(7.2)	(7.0)	(0.8)	(3.2)
Amortization of Prior Service Credit	—	—	5.9	5.8
Change for the Year Ended December 31,	$ 6.8	$ (18.1)	$ 20.0	$ (21.0)

APCo

	Pension Plans		OPEB	
	December 31,			
	2018	2017	2018	2017
Components	(in millions)			
Net Actuarial Loss	$ 172.2	$ 182.5	$ 58.9	$ 48.0
Prior Service Credit	—	—	(50.4)	(60.4)
Recorded as				
Regulatory Assets	$ 169.6	$ 179.9	$ 2.6	$ (11.1)
Deferred Income Taxes	0.5	0.5	1.2	(0.3)
Net of Tax AOCI	2.1	1.7	4.7	(0.8)
Income Tax Expense (a)	—	0.4	—	(0.2)

APCo

	Pension Plans		OPEB	
	2018	2017	2018	2017
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ 0.3	$ (23.3)	$ 12.8	$ (38.6)
Amortization of Actuarial Loss	(10.6)	(10.4)	(1.9)	(6.3)
Amortization of Prior Service Credit (Cost)	—	(0.2)	10.0	10.1
Change for the Year Ended December 31,	$ (10.3)	$ (33.9)	$ 20.9	$ (34.8)

I&M

	Pension Plans		OPEB	
	December 31,			
	2018	2017	2018	2017
Components	(in millions)			
Net Actuarial Loss	$ 80.6	$ 94.9	$ 54.7	$ 42.0
Prior Service Credit	—	—	(47.4)	(56.9)
Recorded as				
Regulatory Assets	$ 78.4	$ 91.8	$ 6.5	$ (14.0)
Deferred Income Taxes	0.5	0.7	0.2	(0.2)
Net of Tax AOCI	1.7	2.0	0.6	(0.6)
Income Tax Expense (a)	—	0.4	—	(0.1)

I&M

	Pension Plans		OPEB	
	2018	2017	2018	2017
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ (4.5)	$ (28.6)	$ 13.9	$ (34.9)
Amortization of Actuarial Loss	(9.8)	(9.7)	(1.2)	(4.4)
Amortization of Prior Service Credit (Cost)	—	(0.2)	9.5	9.4
Change for the Year Ended December 31,	$ (14.3)	$ (38.5)	$ 22.2	$ (29.9)

OPCo

	Pension Plans		OPEB	
	December 31,			
	2018	2017	2018	2017
Components	(in millions)			
Net Actuarial Loss	$ 180.7	$ 189.6	$ 35.5	$ 22.6
Prior Service Credit	—	—	(34.7)	(41.6)
Recorded as				
Regulatory Assets	$ 180.7	$ 189.6	$ 0.8	$ (19.0)

OPCo

	Pension Plans		OPEB	
	2018	2017	2018	2017
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ (0.9)	$ (18.0)	$ 14.0	$ (31.3)
Amortization of Actuarial Loss	(8.0)	(7.8)	(1.1)	(4.3)
Amortization of Prior Service Credit (Cost)	—	(0.1)	6.9	6.9
Change for the Year Ended December 31,	$ (8.9)	$ (25.9)	$ 19.8	$ (28.7)

PSO

	Pension Plans		OPEB	
	December 31,			
	2018	2017	2018	2017
Components	(in millions)			
Net Actuarial Loss	$ 77.6	$ 78.8	$ 28.3	$ 19.8
Prior Service Credit	—	—	(21.6)	(25.9)
Recorded as				
Regulatory Assets	$ 77.6	$ 78.8	$ 6.7	$ (6.1)

PSO

	Pension Plans		OPEB	
	2018	2017	2018	2017
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ 3.2	$ (7.9)	$ 9.0	$ (15.5)
Amortization of Actuarial Loss	(4.4)	(4.3)	(0.5)	(2.0)
Amortization of Prior Service Credit	—	—	4.3	4.3
Change for the Year Ended December 31,	$ (1.2)	$ (12.2)	$ 12.8	$ (13.2)

SWEPCo

	Pension Plans		OPEB	
	December 31,			
	2018	2017	2018	2017
Components	(in millions)			
Net Actuarial Loss	$ 97.4	$ 97.4	$ 33.9	$ 24.7
Prior Service Credit	—	—	(26.2)	(31.4)
Recorded as				
Regulatory Assets	$ 97.4	$ 97.4	$ 4.9	$ (3.7)
Deferred Income Taxes	—	—	0.7	(0.6)
Net of Tax AOCI	—	—	2.1	(2.0)
Income Tax Expense (a)	—	—	—	(0.4)

SWEPCo

	Pension Plans		OPEB	
	2018	2017	2018	2017
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ 5.5	$ (1.5)	$ 9.8	$ (18.4)
Amortization of Actuarial Loss	(5.5)	(4.9)	(0.6)	(2.3)
Amortization of Prior Service Credit (Cost)	—	(0.1)	5.2	5.2
Change for the Year Ended December 31,	$ —	$ (6.5)	$ 14.4	$ (15.5)

(a) Amounts relate to the re-measurement of Deferred Income Taxes as a result of Tax Reform. In accordance with the accounting guidance for "Income Taxes", re-measurement of Deferred Income Taxes related to AOCI must flow through the statement of income.

Determination of Pension Expense

The determination of pension expense or income is based on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return.

Pension and OPEB Assets

The fair value tables within Pension and OPEB Assets present the classification of assets for AEP within the fair value hierarchy. All Level 1, 2, 3 and Other amounts can be allocated to the Registrant Subsidiaries using the percentages in the table below:

	Pension Plan		OPEB	
	December 31,			
Company	**2018**	**2017**	**2018**	**2017**
AEP Texas	8.7%	8.8%	8.5%	8.5%
APCo	12.6%	12.6%	15.5%	15.8%
I&M	12.4%	12.3%	12.2%	12.2%
OPCo	9.9%	9.8%	11.4%	11.5%
PSO	5.6%	5.6%	5.5%	5.5%
SWEPCo	6.0%	6.0%	6.4%	6.4%

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2018:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 277.3	$ —	$ —	$ —	$ 277.3	5.9%
International	384.1	—	—	—	384.1	8.2%
Options	—	18.3	—	—	18.3	0.4%
Common Collective Trusts (c)	—	—	—	370.1	370.1	7.9%
Subtotal – Equities	661.4	18.3	—	370.1	1,049.8	22.4%
Fixed Income (a):						
United States Government and Agency Securities	0.2	1,512.5	—	—	1,512.7	32.2%
Corporate Debt	—	1,082.9	—	—	1,082.9	23.0%
Foreign Debt	—	221.6	—	—	221.6	4.7%
State and Local Government	—	28.2	—	—	28.2	0.6%
Other – Asset Backed	—	7.4	—	—	7.4	0.2%
Subtotal – Fixed Income	0.2	2,852.6	—	—	2,852.8	60.7%
Infrastructure (c)	—	—	—	72.2	72.2	1.5%
Real Estate (c)	—	—	—	220.4	220.4	4.7%
Alternative Investments (c)	—	—	—	444.6	444.6	9.5%
Cash and Cash Equivalents (c)	(0.4)	36.3	—	11.9	47.8	1.0%
Other – Pending Transactions and Accrued Income (b)	—	—	—	8.3	8.3	0.2%
Total	$ 661.2	$ 2,907.2	$ —	$ 1,127.5	$ 4,695.9	100.0%

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(c) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2018:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 233.3	$ —	$ —	$ —	$ 233.3	15.2 %
International	185.9	—	—	—	185.9	12.1 %
Options	—	4.3	—	—	4.3	0.3 %
Common Collective Trusts (b)	—	—	—	226.2	226.2	14.7 %
Subtotal – Equities	419.2	4.3	—	226.2	649.7	42.3 %
Fixed Income:						
Common Collective Trust – Debt (b)	—	—	—	163.6	163.6	10.7 %
United States Government and Agency Securities	0.2	181.5	—	—	181.7	11.8 %
Corporate Debt	—	188.6	—	—	188.6	12.3 %
Foreign Debt	—	35.0	—	—	35.0	2.3 %
State and Local Government	41.8	11.8	—	—	53.6	3.5 %
Other – Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	42.0	417.1	—	163.6	622.7	40.6 %
Trust Owned Life Insurance:						
International Equities	—	49.4	—	—	49.4	3.2 %
United States Bonds	—	154.4	—	—	154.4	10.1 %
Subtotal – Trust Owned Life Insurance	—	203.8	—	—	203.8	13.3 %
Cash and Cash Equivalents (b)	54.4	—	—	4.8	59.2	3.9 %
Other – Pending Transactions and Accrued Income (a)	—	—	—	(1.2)	(1.2)	(0.1)%
Total	$ 515.6	$ 625.2	$ —	$ 393.4	$ 1,534.2	100.0 %

(a) Amounts in “Other” column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(b) Amounts in “Other” column represent investments for which fair value is measured using net asset value per share.

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2017:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 318.6	$ —	$ —	$ —	$ 318.6	6.2%
International	507.7	—	—	—	507.7	9.8%
Options	—	26.9	—	—	26.9	0.5%
Common Collective Trusts (c)	—	—	—	452.9	452.9	8.7%
Subtotal – Equities	826.3	26.9	—	452.9	1,306.1	25.2%
Fixed Income (a):						
United States Government and Agency Securities	—	1,376.5	—	—	1,376.5	26.6%
Corporate Debt	—	1,277.0	—	—	1,277.0	24.7%
Foreign Debt	—	296.9	—	—	296.9	5.7%
State and Local Government	—	31.7	—	—	31.7	0.6%
Other – Asset Backed	—	10.2	—	—	10.2	0.2%
Subtotal – Fixed Income	—	2,992.3	—	—	2,992.3	57.8%
Infrastructure (c)	—	—	—	59.5	59.5	1.2%
Real Estate (c)	—	—	—	290.3	290.3	5.6%
Alternative Investments (c)	—	—	—	446.0	446.0	8.6%
Cash and Cash Equivalents (c)	0.4	35.6	—	21.2	57.2	1.1%
Other – Pending Transactions and Accrued Income (b)	—	—	—	22.7	22.7	0.5%
Total	$ 826.7	$ 3,054.8	$ —	$ 1,292.6	$ 5,174.1	100.0%

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(c) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share.

The following table sets forth a reconciliation of changes in the fair value of AEP's assets classified as Level 3 in the fair value hierarchy for the pension assets:

	Infrastructure	Real Estate	Alternative Investments	Total Level 3
		(in millions)		
Balance as of January 1, 2017	$ 57.6	$ 254.9	$ 411.1	$ 723.6
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	—	—	—	—
Relating to Assets Sold During the Period	—	—	—	—
Purchases and Sales	—	—	—	—
Transfers into Level 3	—	—	—	—
Transfers out of Level 3 (a)	(57.6)	(254.9)	(411.1)	(723.6)
Balance as of December 31, 2017	$ —	$ —	$ —	$ —

(a) The classification of Level 3 assets from the prior year was corrected in the current year presentation and included within the fair value hierarchy table as of December 31, 2017 as "Other" investments for which fair value is measured using net asset value per share in accordance with ASU 2015-07, Disclosure for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent). Management concluded that these disclosure errors were immaterial individually and in the aggregate to all prior periods presented.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2017:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 307.1	$ —	$ —	$ —	$ 307.1	17.7 %
International	306.9	—	—	—	306.9	17.7 %
Options	—	9.4	—	—	9.4	0.5 %
Common Collective Trusts (b)	—	—	—	153.6	153.6	8.9 %
Subtotal – Equities	614.0	9.4	—	153.6	777.0	44.8 %
Fixed Income:						
Common Collective Trust – Debt (b)	—	—	—	185.0	185.0	10.7 %
United States Government and Agency Securities	—	187.4	—	—	187.4	10.8 %
Corporate Debt	—	214.1	—	—	214.1	12.4 %
Foreign Debt	—	40.7	—	—	40.7	2.4 %
State and Local Government	49.7	16.8	—	—	66.5	3.8 %
Other – Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	49.7	459.2	—	185.0	693.9	40.1 %
Trust Owned Life Insurance:						
International Equities	—	105.4	—	—	105.4	6.1 %
United States Bonds	—	118.2	—	—	118.2	6.8 %
Subtotal – Trust Owned Life Insurance	—	223.6	—	—	223.6	12.9 %
Cash and Cash Equivalents (b)	36.7	—	—	4.2	40.9	2.4 %
Other – Pending Transactions and Accrued Income (a)	—	—	—	(2.9)	(2.9)	(0.2)%
Total	$ 700.4	$ 692.2	$ —	$ 339.9	$ 1,732.5	100.0 %

(a) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share.

Accumulated Benefit Obligation

The accumulated benefit obligation for the pension plans is as follows:

Accumulated Benefit Obligation	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Qualified Pension Plan	$ 4,560.7	$ 393.2	$ 588.3	$ 536.3	$ 438.3	$ 238.0	$ 271.6
Nonqualified Pension Plans	64.9	3.6	0.2	0.6	0.2	2.2	1.2
Total as of December 31, 2018	$ 4,625.6	$ 396.8	$ 588.5	$ 536.9	$ 438.5	$ 240.2	$ 272.8

Accumulated Benefit Obligation	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Qualified Pension Plan	$ 4,951.3	$ 421.4	$ 648.0	$ 592.4	$ 483.4	$ 256.9	$ 289.4
Nonqualified Pension Plans	73.9	3.8	0.2	0.4	0.1	2.7	2.2
Total as of December 31, 2017	$ 5,025.2	$ 425.2	$ 648.2	$ 592.8	$ 483.5	$ 259.6	$ 291.6

Obligations in Excess of Fair Values

The tables below show the underfunded pension plans that had obligations in excess of plan assets.

Projected Benefit Obligation

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Projected Benefit Obligation	$ 4,810.3	$ 3.8	$ 603.1	$ 1.2	$ 0.4	$ 2.3	$ 291.4
Fair Value of Plan Assets	4,695.9	—	593.3	—	—	—	281.0
Underfunded Projected Benefit Obligation as of December 31, 2018	$ (114.4)	$ (3.8)	$ (9.8)	$ (1.2)	$ (0.4)	$ (2.3)	$ (10.4)

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Projected Benefit Obligation	$ 78.0	$ 4.0	$ 665.0	$ 1.0	$ 0.4	$ 2.7	$ 314.6
Fair Value of Plan Assets	—	—	651.7	—	—	—	311.7
Underfunded Projected Benefit Obligation as of December 31, 2017	$ (78.0)	$ (4.0)	$ (13.3)	$ (1.0)	$ (0.4)	$ (2.7)	$ (2.9)

Accumulated Benefit Obligation

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Accumulated Benefit Obligation	$ 64.9	$ 3.6	$ 0.2	$ 0.6	$ 0.2	$ 2.2	$ 1.2
Fair Value of Plan Assets	—	—	—	—	—	—	—
Underfunded Accumulated Benefit Obligation as of December 31, 2018	$ (64.9)	$ (3.6)	$ (0.2)	$ (0.6)	$ (0.2)	$ (2.2)	$ (1.2)

	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Accumulated Benefit Obligation	$ 73.9	$ 3.8	$ 0.2	$ 0.4	$ 0.1	$ 2.7	$ 2.2
Fair Value of Plan Assets	—	—	—	—	—	—	—
Underfunded Accumulated Benefit Obligation as of December 31, 2017	$ (73.9)	$ (3.8)	$ (0.2)	$ (0.4)	$ (0.1)	$ (2.7)	$ (2.2)

Estimated Future Benefit Payments and Contributions

The estimated pension benefit payments and contributions to the trust are at least the minimum amount required by the Employee Retirement Income Security Act plus payment of unfunded nonqualified benefits. For the qualified pension plan, additional discretionary contributions may also be made to maintain the funded status of the plan. For OPEB plans, expected payments include the payment of unfunded benefits. The following table provides the estimated contributions and payments by Registrant for 2019:

Company	Pension Plans	OPEB
	(in millions)	
AEP	$ 98.7	$ 4.5
AEP Texas	8.0	0.1
APCo	7.7	2.1
I&M	1.1	—
OPCo	0.5	—
PSO	0.2	—
SWEPCo	7.9	—

The tables below reflect the total benefits expected to be paid from the plan or from the Registrants' assets. The payments include the participants' contributions to the plan for their share of the cost. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for the pension benefits and OPEB are as follows:

Pension Plans	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
2019	$ 339.8	$ 30.8	$ 43.4	$ 36.2	$ 34.3	$ 19.0	$ 21.4
2020	344.2	34.3	42.8	36.4	34.5	19.5	21.8
2021	354.2	34.9	43.4	37.5	34.0	21.2	22.9
2022	357.3	33.5	43.6	38.9	33.9	20.4	23.8
2023	364.1	34.9	44.2	40.3	34.7	23.1	24.0
Years 2024 to 2028, in Total	1,808.2	164.7	220.2	210.6	163.3	102.5	120.5

OPEB Benefit Payments	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
2019	$ 122.0	$ 10.0	$ 22.0	$ 14.8	$ 14.5	$ 6.3	$ 7.1
2020	126.5	10.5	22.5	15.4	14.8	6.8	7.5
2021	127.1	10.7	22.2	15.7	14.8	6.8	7.8
2022	127.2	10.9	22.1	15.7	14.7	7.0	8.0
2023	126.3	10.9	21.6	15.6	14.5	7.1	8.1
Years 2024 to 2028, in Total	618.8	53.6	103.4	75.6	69.1	34.9	41.5

OPEB Medicare Subsidy Receipts	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
2019	$ 0.2	$ —	$ 0.2	$ —	$ —	$ —	$ —
2020	0.2	—	0.2	—	—	—	—
2021	0.3	—	0.2	—	—	—	—
2022	0.3	—	0.2	—	—	—	—
2023	0.3	—	0.2	—	—	—	—
Years 2024 to 2028, in Total	1.5	—	0.7	—	—	—	—

Components of Net Periodic Benefit Cost

The following tables provide the components of net periodic benefit cost (credit) by Registrant for the plans:

<u>AEP</u>	Pension Plans			OPEB		
	Years Ended December 31,					
	2018	2017	2016	2018	2017	2016
	(in millions)					
Service Cost	$ 97.6	$ 96.5	$ 85.8	$ 11.6	$ 11.2	$ 10.2
Interest Cost	187.8	203.1	211.6	47.4	59.3	60.9
Expected Return on Plan Assets	(290.3)	(284.8)	(280.3)	(102.2)	(101.3)	(107.0)
Amortization of Prior Service Cost (Credit)	—	1.0	2.3	(69.1)	(69.1)	(69.0)
Amortization of Net Actuarial Loss	85.2	82.8	83.8	10.5	36.7	31.4
Settlements	2.6	—	—	—	—	—
Net Periodic Benefit Cost (Credit)	82.9	98.6	103.2	(101.8)	(63.2)	(73.5)
Capitalized Portion	(41.1)	(39.9)	(37.8)	(4.9)	25.6	26.9
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 41.8	$ 58.7	$ 65.4	$ (106.7)	$ (37.6)	$ (46.6)

AEP Texas

	Pension Plans			OPEB		
	Years Ended December 31,					
	2018	2017	2016	2018	2017	2016
	(in millions)					
Service Cost	$ 9.2	$ 8.6	$ 7.5	$ 0.9	$ 0.9	$ 0.7
Interest Cost	16.0	17.1	17.8	3.8	4.9	5.1
Expected Return on Plan Assets	(25.6)	(25.0)	(24.5)	(8.6)	(8.8)	(9.3)
Amortization of Prior Service Cost (Credit)	—	—	0.4	(5.9)	(5.8)	(6.0)
Amortization of Net Actuarial Loss	7.2	7.0	7.1	0.8	3.2	2.8
Net Periodic Benefit Cost (Credit)	6.8	7.7	8.3	(9.0)	(5.6)	(6.7)
Capitalized Portion	(4.8)	(4.0)	(3.6)	(0.5)	2.9	3.4
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 2.0	$ 3.7	$ 4.7	$ (9.5)	$ (2.7)	$ (3.3)

APCo

	Pension Plans			OPEB		
	Years Ended December 31,					
	2018	2017	2016	2018	2017	2016
	(in millions)					
Service Cost	$ 9.3	$ 9.4	$ 8.1	$ 1.1	$ 1.1	$ 1.0
Interest Cost	23.5	25.7	27.2	8.2	10.6	10.8
Expected Return on Plan Assets	(36.6)	(35.8)	(35.3)	(16.0)	(16.5)	(17.3)
Amortization of Prior Service Cost (Credit)	—	0.2	0.1	(10.0)	(10.1)	(10.1)
Amortization of Net Actuarial Loss	10.6	10.4	10.8	1.9	6.3	5.4
Net Periodic Benefit Cost (Credit)	6.8	9.9	10.9	(14.8)	(8.6)	(10.2)
Capitalized Portion	(3.8)	(4.0)	(4.1)	(0.5)	3.5	3.9
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 3.0	$ 5.9	$ 6.8	$ (15.3)	$ (5.1)	$ (6.3)

I&M

	Pension Plans			OPEB		
	Years Ended December 31,					
	2018	2017	2016	2018	2017	2016
	(in millions)					
Service Cost	$ 13.6	$ 14.0	$ 12.2	$ 1.6	$ 1.6	$ 1.5
Interest Cost	22.1	24.3	25.3	5.4	6.9	7.0
Expected Return on Plan Assets	(35.7)	(34.6)	(33.6)	(12.3)	(12.2)	(12.9)
Amortization of Prior Service Cost (Credit)	—	0.2	0.1	(9.5)	(9.4)	(9.4)
Amortization of Net Actuarial Loss	9.8	9.7	10.0	1.2	4.4	3.7
Net Periodic Benefit Cost (Credit)	9.8	13.6	14.0	(13.6)	(8.7)	(10.1)
Capitalized Portion	(5.6)	(5.5)	(3.3)	(0.7)	3.5	2.4
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 4.2	$ 8.1	$ 10.7	$ (14.3)	$ (5.2)	$ (7.7)

OPCo

	Pension Plans			OPEB		
	Years Ended December 31,					
	2018	2017	2016	2018	2017	2016
	(in millions)					
Service Cost	$ 7.7	$ 7.5	$ 6.5	$ 0.9	$ 0.9	$ 0.8
Interest Cost	17.7	19.4	20.6	5.1	6.7	7.0
Expected Return on Plan Assets	(28.8)	(27.9)	(27.6)	(11.7)	(11.9)	(13.0)
Amortization of Prior Service Cost (Credit)	—	0.1	0.1	(6.9)	(6.9)	(6.9)
Amortization of Net Actuarial Loss	8.0	7.8	8.1	1.1	4.3	3.8
Net Periodic Benefit Cost (Credit)	4.6	6.9	7.7	(11.5)	(6.9)	(8.3)
Capitalized Portion	(3.6)	(3.3)	(3.4)	(0.4)	3.3	3.7
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 1.0	$ 3.6	$ 4.3	$ (11.9)	$ (3.6)	$ (4.6)

PSO	Pension Plans			OPEB		
	Years Ended December 31,					
	2018	2017	2016	2018	2017	2016
	(in millions)					
Service Cost	$ 7.0	$ 6.4	$ 6.2	$ 0.7	$ 0.7	$ 0.6
Interest Cost	9.9	10.7	11.2	2.5	3.2	3.3
Expected Return on Plan Assets	(16.1)	(15.6)	(15.5)	(5.6)	(5.6)	(6.1)
Amortization of Prior Service Cost (Credit)	—	—	0.3	(4.3)	(4.3)	(4.3)
Amortization of Net Actuarial Loss	4.4	4.3	4.4	0.5	2.0	1.8
Net Periodic Benefit Cost (Credit)	5.2	5.8	6.6	(6.2)	(4.0)	(4.7)
Capitalized Portion	(2.6)	(2.1)	(2.4)	(0.3)	1.4	1.7
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 2.6	$ 3.7	$ 4.2	$ (6.5)	$ (2.6)	$ (3.0)

SWEPCo	Pension Plans			OPEB		
	Years Ended December 31,					
	2018	2017	2016	2018	2017	2016
	(in millions)					
Service Cost	$ 9.3	$ 8.7	$ 8.1	$ 0.9	$ 0.9	$ 0.8
Interest Cost	11.3	12.3	12.4	2.8	3.6	3.6
Expected Return on Plan Assets	(17.3)	(17.0)	(16.4)	(6.4)	(6.3)	(6.8)
Amortization of Prior Service Cost (Credit)	—	0.1	0.3	(5.2)	(5.2)	(5.0)
Amortization of Net Actuarial Loss	5.1	4.9	4.8	0.6	2.3	1.9
Settlements	0.4	—	—	—	—	—
Net Periodic Benefit Cost (Credit)	8.8	9.0	9.2	(7.3)	(4.7)	(5.5)
Capitalized Portion	(3.1)	(2.7)	(2.7)	(0.3)	1.4	1.6
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 5.7	$ 6.3	$ 6.5	$ (7.6)	$ (3.3)	$ (3.9)

American Electric Power System Retirement Savings Plan

AEP sponsors the American Electric Power System Retirement Savings Plan, a defined contribution retirement savings plan for substantially all employees who are not covered by a retirement savings plan of the UMWA. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions.

The following table provides the cost for matching contributions to the retirement savings plans by Registrant:

	Year Ended December 31,		
Company	2018	2017	2016
	(in millions)		
AEP	$ 71.8	$ 74.6	$ 72.9
AEP Texas	5.7	6.0	5.2
APCo	7.5	7.4	7.3
I&M	10.5	10.7	10.9
OPCo	6.3	6.1	5.6
PSO	4.5	5.0	4.3
SWEPCo	5.9	6.0	5.7

UMWA Benefits

Health and Welfare Benefits (Applies to AEP and APCo)

AEP provides health and welfare benefits for certain unionized employees, retirees and their survivors who meet eligibility requirements. APCo also provides the same UMWA health and welfare benefits for certain unionized mining retirees and their survivors who meet eligibility requirements. AEP and APCo administer the health and welfare benefits and pay them from their general assets.

Multiemployer Pension Benefits (Applies to AEP)

UMWA pension benefits are provided through the United Mine Workers of America 1974 Pension Plan (Employer Identification Number: 52-1050282, Plan Number 002), a multiemployer plan. The UMWA pension benefits are administered by a board of trustees appointed in equal numbers by the UMWA and the Bituminous Coal Operators' Association (BCOA), an industry bargaining association. AEP makes contributions to the United Mine Workers of America 1974 Pension Plan based on provisions in its labor agreement and the plan documents. The UMWA pension plan is different from single-employer plans as an employer's contributions may be used to provide benefits to employees of other participating employers. A withdrawing employer may be subject to a withdrawal liability, which is calculated based upon that employer's share of the plan's unfunded benefit obligations. If an employer fails to make required contributions or if its payments in connection with its withdrawal liability fall short of satisfying its share of the plan's unfunded benefit obligations, the remaining employers may be allocated a greater share of the remaining unfunded plan obligations. Under the Pension Protection Act of 2006 (PPA), the UMWA pension plan was in Critical and Declining Status for the plan years ending June 30, 2018 and 2017, without utilization of extended amortization provisions. As required under the PPA, the Plan adopted a Rehabilitation Plan in February 2015 which was updated in 2016, 2017 and April 2018.

The amounts contributed by AEP affiliates in 2018, 2017 and 2016 were immaterial and represent less than 5% of the total contributions in the plan's latest annual report based on the plan year ended June 30, 2017. UMWA pension contributions included a surcharge of 10% from July 2015 through June 2016 at which time new base contribution rates went into effect with no associated surcharges.

Under the terms of the UMWA pension plan, contributions will be required to continue beyond the December 31, 2020 expiration of the current collective bargaining agreement between the Cook Coal Terminal (CCT) facility and the UMWA, whether or not the term of that agreement is extended or a subsequent agreement is entered, so long as both the UMWA pension plan remains in effect and an AEP affiliate continues to operate the facility covered by the current collective bargaining agreement. The contribution rate applicable would be determined in accordance with the terms of the UMWA pension plan by reference to the National Bituminous Coal Wage Agreement, subject to periodic revisions, between the UMWA and the BCOA. If the UMWA pension plan would terminate or an AEP affiliate would cease operation of the facility without arranging for a successor operator to assume its liability, the withdrawal liability obligation would be triggered.

Based upon the planned closure of CCT in 2022, AEP records a UMWA pension withdrawal liability on the balance sheet. The UMWA pension withdrawal liability is re-measured annually and is the estimated value of the company's proportionate share of the plan's unfunded vested liabilities. As of December 31, 2018 and 2017, the liability balance was $15 million and $19 million, respectively. AEP recovers the estimated UMWA pension withdrawal liability through fuel clauses in certain regulated jurisdictions. AEP records a regulatory asset on the balance sheets when the UMWA pension withdrawal liability exceeds the cumulative billings collected and a regulatory liability on the balance sheets when the cumulative billings collected exceed the withdrawal liability. As of December 31, 2018, AEP recorded a regulatory liability on the balance sheets for $3 million and as of December 31, 2017, AEP recorded a regulatory asset on the balance sheets for $1 million. If any portion of the UMWA pension withdrawal liability is not recoverable, it could reduce future net income and cash flows and impact financial condition.

9. BUSINESS SEGMENTS

The disclosures in this note apply to all Registrants unless indicated otherwise.

AEP's Reportable Segments

AEP's primary business is the generation, transmission and distribution of electricity. Within its Vertically Integrated Utilities segment, AEP centrally dispatches generation assets and manages its overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

AEP's reportable segments and their related business activities are outlined below:

Vertically Integrated Utilities

- Generation, transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEGCo, APCo, I&M, KGPCo, KPCo, PSO, SWEPCo and WPCo.

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEP Texas and OPCo.
- OPCo purchases energy and capacity at auction to serve SSO customers and provides transmission and distribution services for all connected load.

AEP Transmission Holdco

- Development, construction and operation of transmission facilities through investments in AEPTCo. These investments have FERC-approved returns on equity.
- Development, construction and operation of transmission facilities through investments in AEP's transmission-only joint ventures. These investments have PUCT-approved or FERC-approved returns on equity.

Generation & Marketing

- Competitive generation in ERCOT and PJM.
- Marketing, risk management and retail activities in ERCOT, PJM, SPP and MISO.
- Contracted renewable energy investments and management services.

The remainder of AEP's activities are presented as Corporate and Other. While not considered a reportable segment, Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries, Parent's guarantee revenue received from affiliates, investment income, interest income, interest expense, income tax expense and other nonallocated costs.

The tables below present AEP's reportable segment income statement information for the years ended December 31, 2018, 2017 and 2016 and reportable segment balance sheet information as of December 31, 2018 and 2017.

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments		Consolidated
	(in millions)							
2018								
Revenues from:								
External Customers	$ 9,556.7	$ 4,552.3	$ 248.6	$ 1,818.1	$ 20.0	$ —		$ 16,195.7
Other Operating Segments	88.8	100.8	555.5	122.2	75.1	(942.4)		—
Total Revenues	$ 9,645.5	$ 4,653.1	$ 804.1	$ 1,940.3	$ 95.1	$ (942.4)		$ 16,195.7
Asset Impairments and Other Related Charges	$ 3.4	$ —	$ —	$ 47.7	$ 19.5	$ —		$ 70.6
Depreciation and Amortization	1,316.2	734.1	137.8	41.0	0.4	57.1	(b)	2,286.6
Interest and Investment Income	11.7	4.2	2.5	13.1	31.0	(50.9)		11.6
Carrying Costs Income (Expense)	5.3	1.7	(0.4)	—	—	—		6.6
Interest Expense	567.8	248.1	90.7	14.9	122.6	(59.7)	(b)	984.4
Income Tax Expense (Benefit)	5.7	42.4	95.3	(49.2)	21.1	—		115.3
Net Income (Loss)	$ 995.5	$ 527.4	$ 373.0	$ 134.7	$ (99.3)	$ —		$ 1,931.3
Gross Property Additions	$ 2,282.2	$ 2,162.4	$ 1,614.1	$ 289.7	$ 16.3	$ (39.2)		$ 6,325.5
Total Property, Plant and Equipment	$ 45,365.1	$ 18,126.7	$ 8,659.5	$ 893.3	$ 395.2	$ (354.6)	(b)	$ 73,085.2
Accumulated Depreciation and Amortization	13,822.5	3,833.7	282.8	47.0	186.6	(186.5)	(b)	17,986.1
Total Property, Plant and Equipment – Net	$ 31,542.6	$ 14,293.0	$ 8,376.7	$ 846.3	$ 208.6	$ (168.1)	(b)	$ 55,099.1
Total Assets	$ 38,874.3	$ 17,083.4	$ 9,543.7	$ 1,979.7	$ 4,036.5 (c)	$ (2,714.8)	(b) (d)	$ 68,802.8
Investments in Equity Method Investees	$ 39.6	$ 2.9	$ 750.9	$ 26.7	$ 26.1	$ —		$ 846.2
Long-term Debt Due Within One Year:								
Nonaffiliated	$ 1,066.3	$ 549.1	$ 85.0	$ 0.1	$ (2.0) (e)	$ —		$ 1,698.5
Long-term Debt:								
Affiliated	50.0	—	—	32.2	—	(82.2)		—
Nonaffiliated	11,442.7	5,048.8	2,888.6	(0.3)	2,268.4 (e)	—		21,648.2
Total Long-term Debt	$ 12,559.0	$ 5,597.9	$ 2,973.6	$ 32.0	$ 2,266.4	$ (82.2)		$ 23,346.7

2017	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Revenues from:							
External Customers	$ 9,095.1	$ 4,328.9	$ 178.4	$ 1,771.4	$ 51.1	$ —	$ 15,424.9
Other Operating Segments	96.9	90.4	588.3	103.7	69.7	(949.0)	—
Total Revenues	$ 9,192.0	$ 4,419.3	$ 766.7	$ 1,875.1	$ 120.8	$ (949.0)	$ 15,424.9
Asset Impairments and Other Related Charges	$ 33.6	$ —	$ —	$ 53.5	$ —	$ —	$ 87.1
Depreciation and Amortization	1,142.5	667.5	102.2	24.2	0.3	60.5 (b)	1,997.2
Interest and Investment Income	6.8	7.7	1.2	10.3	23.3	(33.3)	16.0
Carrying Costs Income (Expense)	15.2	3.6	(0.2)	—	—	—	18.6
Interest Expense	540.0	244.1	72.8	18.5	63.9	(44.3) (b)	895.0
Income Tax Expense	425.6	127.2	189.8	189.7	37.4	—	969.7
Net Income (Loss)	$ 803.3	$ 636.4	$ 355.6	$ 166.0	$ (32.4)	$ —	$ 1,928.9
Gross Property Additions	$ 2,343.2	$ 1,558.4	$ 1,542.8	$ 328.5	$ 15.6	$ (90.4)	$ 5,698.1
Total Property, Plant and Equipment	$ 43,294.4	$ 16,371.2	$ 7,110.2	$ 644.6	$ 374.5	$ (366.4) (b)	$ 67,428.5
Accumulated Depreciation and Amortization	13,153.4	3,768.3	176.6	75.0	180.6	(186.9) (b)	17,167.0
Total Property, Plant and Equipment – Net	$ 30,141.0	$ 12,602.9	$ 6,933.6	$ 569.6	$ 193.9	$ (179.5) (b)	$ 50,261.5
Total Assets	$ 37,579.7	$ 16,060.7	$ 8,141.8	$ 2,009.8	$ 3,959.1 (c)	$ (3,022.0) (b) (d)	$ 64,729.1
Investments in Equity Method Investees	$ 37.1	$ 1.5	$ 742.9	$ 16.6	$ 14.2	$ —	$ 812.3
Long-term Debt Due Within One Year:							
Nonaffiliated	$ 1,038.1	$ 663.1	$ 50.0	$ —	$ 2.5	$ —	$ 1,753.7
Long-term Debt:							
Affiliated	50.0	—	—	32.2	—	(82.2)	—
Nonaffiliated	10,801.4	4,705.4	2,631.3	(0.3)	1,281.8	—	19,419.6
Total Long-term Debt	$ 11,889.5	$ 5,368.5	$ 2,681.3	$ 31.9	$ 1,284.3	$ (82.2)	$ 21,173.3

2016	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other(a)	Reconciling Adjustments	Consolidated
	(in millions)						
Revenues from:							
External Customers	$ 9,012.4	$ 4,328.3	$ 145.9	$ 2,858.7	$ 34.8	$ —	$ 16,380.1
Other Operating Segments	79.5	94.1	366.9	127.3	70.3	(738.1)	—
Total Revenues	$ 9,091.9	$ 4,422.4	$ 512.8	$ 2,986.0	$ 105.1	$ (738.1)	$ 16,380.1
Asset Impairments and Other Related Charges	$ 10.5	$ —	$ —	$ 2,257.3	$ —	$ —	$ 2,267.8
Depreciation and Amortization	1,073.8	649.9	67.1	154.6	0.2	16.7 (b)	1,962.3
Interest and Investment Income	4.8	14.8	0.4	1.4	11.8	(16.9)	16.3
Carrying Costs Income (Expense)	10.5	20.0	(0.3)	—	—	(14.0)	16.2
Interest Expense	522.1	256.9	50.3	35.8	40.5	(28.4) (b)	877.2
Income Tax Expense (Benefit)	397.3	205.1	134.1	(666.5)	(143.7)	—	(73.7)
Income (Loss) from Continuing Operations	984.0	482.1	269.3	(1,198.0)	83.1	—	620.5
Income (Loss) from Discontinued Operations, Net of Tax	—	—	—	—	(2.5)	—	(2.5)
Net Income (Loss)	$ 984.0	$ 482.1	$ 269.3	$ (1,198.0)	$ 80.6	$ —	$ 618.0
Gross Property Additions	$ 2,237.0	$ 1,058.3	$ 1,265.8	$ 336.2	$ 9.8	$ (18.1)	$ 4,889.0
Total Assets	$ 37,428.3	$ 14,802.4	$ 6,384.8	$ 3,386.1	$ 3,883.4 (c)	$ (2,417.3) (b) (d)	$ 63,467.7

(a) Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes Parent's guarantee revenue received from affiliates, investment income, interest income, interest expense and other nonallocated costs.
(b) Includes eliminations due to an intercompany capital lease.
(c) Includes elimination of AEP Parent's investments in wholly-owned subsidiary companies.
(d) Reconciling Adjustments for Total Assets primarily include elimination of intercompany advances to affiliates and intercompany accounts receivable.
(e) Amounts reflect the impact of fair value hedge accounting. See "Accounting for Fair Value Hedging Strategies" section of Note 10 for additional information.

Registrant Subsidiaries' Reportable Segments (Applies to all Registrant Subsidiaries except AEPTCo)

The Registrant Subsidiaries each have one reportable segment, an integrated electricity generation, transmission and distribution business for APCo, I&M, PSO and SWEPCo, and an integrated electricity transmission and distribution business for AEP Texas and OPCo. Other activities are insignificant. The Registrant Subsidiaries' operations are managed on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight on the business process, cost structures and operating results.

AEPTCo's Reportable Segments

AEPTCo Parent is the holding company of seven FERC-regulated transmission-only electric utilities. The seven State Transcos have been identified as operating segments of AEPTCo under the accounting guidance for "Segment Reporting." The State Transcos business consists of developing, constructing and operating transmission facilities at the request of the RTOs in which they operate and in replacing and upgrading facilities, assets and components of the existing AEP transmission system as needed to maintain reliability standards and provide service to AEP's wholesale and retail customers. The State Transcos are regulated for rate-making purposes exclusively by the FERC and earn revenues through tariff rates charged for the use of their electric transmission systems.

AEPTCo's Chief Operating Decision Maker makes operating decisions, allocates resources to and assesses performance based on these operating segments. The seven State Transcos operating segments all have similar economic characteristics and meet all of the criteria under the accounting guidance for "Segment Reporting" to be aggregated into one operating segment. As a result, AEPTCo has one reportable segment. The remainder of AEPTCo's activity is presented in AEPTCo Parent. While not considered a reportable segment, AEPTCo Parent represents the activity of the holding company which primarily relates to debt financing activity and general corporate activities.

The tables below present AEPTCo's reportable segment income statement information for the years ended December 31, 2018, 2017 and 2016 and reportable segment balance sheet information as of December 31, 2018 and 2017.

2018	State Transcos	AEPTCo Parent		Reconciling Adjustments		AEPTCo Consolidated
	(in millions)					
Revenues from:						
External Customers	$ 177.0	$ —		$ —		$ 177.0
Sales to AEP Affiliates	598.9	—		—		598.9
Other Revenues	0.2	—		—		0.2
Total Revenues	$ 776.1	$ —		$ —		$ 776.1
Depreciation and Amortization	$ 133.9	$ —		$ —		$ 133.9
Interest Income	1.3	104.6		(103.4)	(a)	2.5
Allowance for Equity Funds Used During Construction	70.6	—		—		70.6
Interest Expense	83.2	103.4		(103.4)	(a)	83.2
Income Tax Expense	83.9	0.2		—		84.1
Net Income	$ 314.9	$ 1.0	(b)	$ —		$ 315.9
Gross Property Additions	$ 1,570.8	$ —		$ —		$ 1,570.8
Total Transmission Property	$ 8,268.1	$ —		$ —		$ 8,268.1
Accumulated Depreciation and Amortization	271.9	—		—		271.9
Total Transmission Property - Net	$ 7,996.2	$ —		$ —		$ 7,996.2
Notes Receivable - Affiliated	$ —	$ 2,823.0		$ (2,823.0)	(c)	$ —
Total Assets	$ 8,406.8	$ 2,857.1	(d)	$ (2,869.8)	(e)	$ 8,394.1
Total Long-Term Debt	$ 2,850.0	$ 2,823.0		$ (2,850.0)	(c)	$ 2,823.0

2017	State Transcos (f)	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated (f)
	(in millions)			
Revenues from:				
External Customers	$ 138.0	$ —	$ —	$ 138.0
Sales to AEP Affiliates	568.1	—	—	568.1
Other Revenues	0.8	—	—	0.8
Total Revenues	$ 706.9	$ —	$ —	$ 706.9
Depreciation and Amortization	$ 95.7	$ —	$ —	$ 95.7
Interest Income	0.7	82.9	(82.4) (a)	1.2
Allowance for Equity Funds Used During Construction	49.0	—	—	49.0
Interest Expense	70.2	82.4	(82.4) (a)	70.2
Income Tax Expense	142.0	0.2	—	142.2
Net Income	$ 270.4	$ 0.3 (b)	$ —	$ 270.7
Gross Property Additions	$ 1,522.5	$ —	$ —	$ 1,522.5
Total Transmission Property	$ 6,770.5	$ —	$ —	$ 6,770.5
Accumulated Depreciation and Amortization	152.6	—	—	152.6
Total Transmission Property - Net	$ 6,617.9	$ —	$ —	$ 6,617.9
Notes Receivable - Affiliated	$ —	$ 2,550.4	$ (2,550.4) (c)	$ —
Total Assets	$ 7,086.9	$ 2,590.1 (d)	$ (2,594.9) (e)	$ 7,082.1
Total Long-Term Debt	$ 2,575.0	$ 2,550.4	$ (2,575.0) (c)	$ 2,550.4

2016	State Transcos	AEPTCo Parent	Reconciling Adjustments	AEPTCo Consolidated
	(in millions)			
Revenues from:				
External Customers	$ 110.4	$ —	$ —	$ 110.4
Sales to AEP Affiliates	367.5	—	—	367.5
Other	0.1	—	—	0.1
Total Revenues	$ 478.0	$ —	$ —	$ 478.0
Depreciation and Amortization	$ 65.9	$ —	$ —	$ 65.9
Interest Income	0.1	57.8	(57.5) (a)	0.4
Allowance for Equity Funds Used During Construction	52.3	—	—	52.3
Interest Expense	45.6	57.9	(57.5) (a)	46.0
Income Tax Expense (Benefit)	94.4	(0.3)	—	94.1
Net Income (Loss)	$ 193.3	$ (0.6) (b)	$ —	$ 192.7
Gross Property Additions	$ 1,166.0	$ —	$ —	$ 1,166.0
Total Assets	$ 5,337.5	$ 1,987.7 (d)	$ (1,975.4) (e)	$ 5,349.8

(a) Elimination of intercompany interest income/interest expense on affiliated debt arrangement.
(b) Includes elimination of AEPTCo Parent's equity earnings in the State Transcos.
(c) Elimination of intercompany debt.
(d) Includes elimination of AEPTCo Parent's investments in the State Transcos.
(e) Primarily relates to elimination of Notes Receivable from the State Transcos.
(f) The amounts presented reflect the revisions made to AEPTCo's previously issued financial statements. See the "Revisions to Previously Issued Financial Statements" section of Note 1 for additional information.

10. DERIVATIVES AND HEDGING

The disclosures in this note apply to all Registrants unless indicated otherwise. For the periods presented, AEPTCo did not have any derivative and hedging activity.

The Registrants adopted ASU 2017-12 in the second quarter of 2018, effective January 1, 2018. See Note 2 - New Accounting Pronouncements for additional information.

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of AEP subsidiaries, including the Registrant Subsidiaries. AEPEP is agent for and transacts on behalf of other AEP subsidiaries.

The Registrants are exposed to certain market risks as major power producers and participants in the electricity, capacity, natural gas, coal and emission allowance markets. These risks include commodity price risks which may be subject to capacity risk, interest rate risk, credit risk and foreign currency exchange risk. These risks represent the risk of loss that may impact the Registrants due to changes in the underlying market prices or rates. Management utilizes derivative instruments to manage these risks.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

The strategy surrounding the use of derivative instruments primarily focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. The risk management strategies also include the use of derivative instruments for trading purposes which focus on seizing market opportunities to create value driven by expected changes in the market prices of the commodities. To accomplish these objectives, the Registrants primarily employ risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

The Registrants utilize power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. The Registrants utilize interest rate derivative contracts in order to manage the interest rate exposure associated with the commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. The Registrants also utilize derivative contracts to manage interest rate risk associated with debt financing. For disclosure purposes, these risks are grouped as "Interest Rate." The amount of risk taken is determined by the Commercial Operations, Energy Supply and Finance groups in accordance with established risk management policies as approved by the Finance Committee of the Board of Directors.

The following tables represent the gross notional volume of the Registrants' outstanding derivative contracts:

Notional Volume of Derivative Instruments
December 31, 2018

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Commodity:								
Power	MWhs	371.1	—	66.4	40.9	7.8	15.2	4.5
Natural Gas	MMBtus	87.9	—	4.0	2.3	—	—	15.2
Heating Oil and Gasoline	Gallons	7.4	1.5	1.4	0.7	1.8	0.7	0.8
Interest Rate	USD	$ 37.7	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate	USD	$ 500.0	$ —	$ —	$ —	$ —	$ —	$ —

Notional Volume of Derivative Instruments
December 31, 2017

Primary Risk Exposure	Unit of Measure	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Commodity:								
Power	MWhs	358.7	—	57.4	38.5	10.4	10.3	22.7
Coal	Tons	2.0	—	—	2.0	—	—	—
Natural Gas	MMBtus	53.7	—	1.1	0.7	—	—	18.3
Heating Oil and Gasoline	Gallons	6.9	1.4	1.3	0.7	1.6	0.7	0.8
Interest Rate	USD	$ 50.7	$ —	$ —	$ —	$ —	$ —	$ —
Interest Rate	USD	$ 500.0	$ —	$ —	$ —	$ —	$ —	$ —

Fair Value Hedging Strategies (Applies to AEP)

Parent enters into interest rate derivative transactions as part of an overall strategy to manage the mix of fixed-rate and floating-rate debt. Certain interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of fixed-rate debt to a floating rate. Provided specific criteria are met, these interest rate derivatives may be designated as fair value hedges.

Cash Flow Hedging Strategies

The Registrants utilize cash flow hedges on certain derivative transactions for the purchase and sale of power ("Commodity") in order to manage the variable price risk related to forecasted purchases and sales. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and purchases. The Registrants do not hedge all commodity price risk.

The Registrants utilize a variety of interest rate derivative transactions in order to manage interest rate risk exposure. The Registrants also utilize interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. The Registrants do not hedge all interest rate exposure.

At times, the Registrants are exposed to foreign currency exchange rate risks primarily when some fixed assets are purchased from foreign suppliers. In accordance with AEP's risk management policy, the Registrants may utilize foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. The Registrants do not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, the Registrants apply valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management's estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," the Registrants reflect the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, the Registrants are required to post or receive cash collateral based on third party contractual agreements and risk profiles. AEP netted cash collateral received from third parties against short-term and long-term risk management assets in the amounts of $18 million and $9.4 million as of December 31, 2018 and 2017, respectively. AEP netted cash collateral paid to third parties against short-term and long-term risk management liabilities in the amounts of $4 million and $9 million as of December 31, 2018 and 2017, respectively. The netted cash collateral from third parties against short-term and long-term risk management assets and netted cash collateral paid to third parties against short-term and long-term risk management liabilities were immaterial for the other Registrants as of December 31, 2018 and 2017.

The following tables represent the gross fair value of the Registrants' derivative activity on the balance sheets:

AEP

Fair Value of Derivative Instruments
December 31, 2018

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in millions)			
Current Risk Management Assets	$ 397.5	$ 28.5	$ —	$ 426.0	$ (263.2)	$ 162.8
Long-term Risk Management Assets	276.4	16.0	—	292.4	(38.4)	254.0
Total Assets	673.9	44.5	—	718.4	(301.6)	416.8
Current Risk Management Liabilities	293.8	13.2	2.0	309.0	(254.0)	55.0
Long-term Risk Management Liabilities	225.7	56.1	15.4	297.2	(33.8)	263.4
Total Liabilities	519.5	69.3	17.4	606.2	(287.8)	318.4
Total MTM Derivative Contract Net Assets (Liabilities)	$ 154.4	$ (24.8)	$ (17.4)	$ 112.2	$ (13.8)	$ 98.4

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in millions)			
Current Risk Management Assets	$ 389.0	$ 17.5	$ 2.5	$ 409.0	$ (282.8)	$ 126.2
Long-term Risk Management Assets	300.9	6.3	—	307.2	(25.1)	282.1
Total Assets	689.9	23.8	2.5	716.2	(307.9)	408.3
Current Risk Management Liabilities	334.6	9.0	—	343.6	(282.0)	61.6
Long-term Risk Management Liabilities	280.6	58.3	8.6	347.5	(25.5)	322.0
Total Liabilities	615.2	67.3	8.6	691.1	(307.5)	383.6
Total MTM Derivative Contract Net Assets (Liabilities)	$ 74.7	$ (43.5)	$ (6.1)	$ 25.1	$ (0.4)	$ 24.7

AEP Texas

Fair Value of Derivative Instruments
December 31, 2018

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ —	$ —	$ —
Long-term Risk Management Assets	—	—	—
Total Assets	—	—	—
Current Risk Management Liabilities	0.7	(0.5)	0.2
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.7	(0.5)	0.2
Total MTM Derivative Contract Net Assets (Liabilities)	$ (0.7)	$ 0.5	$ (0.2)

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 0.5	$ —	$ 0.5
Long-term Risk Management Assets	—	—	—
Total Assets	0.5	—	0.5
Current Risk Management Liabilities	—	—	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	—	—	—
Total MTM Derivative Contract Net Assets	$ 0.5	$ —	$ 0.5

APCo

Fair Value of Derivative Instruments
December 31, 2018

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 114.4	$ (57.2)	$ 57.2
Long-term Risk Management Assets	3.1	(2.2)	0.9
Total Assets	117.5	(59.4)	58.1
Current Risk Management Liabilities	56.7	(56.3)	0.4
Long-term Risk Management Liabilities	2.4	(2.2)	0.2
Total Liabilities	59.1	(58.5)	0.6
Total MTM Derivative Contract Net Assets (Liabilities)	$ 58.4	$ (0.9)	$ 57.5

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 75.6	$ (50.7)	$ 24.9
Long-term Risk Management Assets	2.4	(1.3)	1.1
Total Assets	78.0	(52.0)	26.0

Current Risk Management Liabilities	50.6	(49.3)	1.3
Long-term Risk Management Liabilities	1.4	(1.2)	0.2
Total Liabilities	52.0	(50.5)	1.5
Total MTM Derivative Contract Net Assets (Liabilities)	$ 26.0	$ (1.5)	$ 24.5

I&M

Fair Value of Derivative Instruments
December 31, 2018

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 50.4	$ (41.8)	$ 8.6
Long-term Risk Management Assets	2.0	(1.4)	0.6
Total Assets	52.4	(43.2)	9.2
Current Risk Management Liabilities	41.1	(40.8)	0.3
Long-term Risk Management Liabilities	1.6	(1.5)	0.1
Total Liabilities	42.7	(42.3)	0.4
Total MTM Derivative Contract Net Assets (Liabilities)	$ 9.7	$ (0.9)	$ 8.8

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 47.2	$ (39.6)	$ 7.6
Long-term Risk Management Assets	1.6	(0.9)	0.7
Total Assets	48.8	(40.5)	8.3
Current Risk Management Liabilities	48.5	(45.0)	3.5
Long-term Risk Management Liabilities	0.9	(0.8)	0.1
Total Liabilities	49.4	(45.8)	3.6
Total MTM Derivative Contract Net Assets (Liabilities)	$ (0.6)	$ 5.3	$ 4.7

OPCo

Fair Value of Derivative Instruments
December 31, 2018

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ —	$ —	$ —
Long-term Risk Management Assets	—	—	—
Total Assets	—	—	—
Current Risk Management Liabilities	6.4	(0.6)	5.8
Long-term Risk Management Liabilities	93.8	—	93.8
Total Liabilities	100.2	(0.6)	99.6
Total MTM Derivative Contract Net Assets (Liabilities)	$ (100.2)	$ 0.6	$ (99.6)

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 0.6	$ —	$ 0.6
Long-term Risk Management Assets	—	—	—
Total Assets	0.6	—	0.6

Current Risk Management Liabilities	6.4	—	6.4
Long-term Risk Management Liabilities	126.0	—	126.0
Total Liabilities	132.4	—	132.4
Total MTM Derivative Contract Net Liabilities	$ (131.8)	$ —	$ (131.8)

PSO

Fair Value of Derivative Instruments
December 31, 2018

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 10.9	$ (0.5)	$ 10.4
Long-term Risk Management Assets	—	—	—
Total Assets	10.9	(0.5)	10.4
Current Risk Management Liabilities	1.7	(0.7)	1.0
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	1.7	(0.7)	1.0
Total MTM Derivative Contract Net Assets	$ 9.2	$ 0.2	$ 9.4

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 6.6	$ (0.2)	$ 6.4
Long-term Risk Management Assets	—	—	—
Total Assets	6.6	(0.2)	6.4
Current Risk Management Liabilities	0.2	(0.2)	—
Long-term Risk Management Liabilities	—	—	—
Total Liabilities	0.2	(0.2)	—
Total MTM Derivative Contract Net Assets	$ 6.4	$ —	$ 6.4

SWEPCo

Fair Value of Derivative Instruments
December 31, 2018

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 5.6	$ (0.8)	$ 4.8
Long-term Risk Management Assets	—	—	—
Total Assets	5.6	(0.8)	4.8
Current Risk Management Liabilities	1.5	(1.1)	0.4
Long-term Risk Management Liabilities	2.2	—	2.2
Total Liabilities	3.7	(1.1)	2.6
Total MTM Derivative Contract Net Assets	$ 1.9	$ 0.3	$ 2.2

Fair Value of Derivative Instruments
December 31, 2017

Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in millions)	
Current Risk Management Assets	$ 7.0	$ (0.6)	$ 6.4
Long-term Risk Management Assets	—	—	—
Total Assets	7.0	(0.6)	6.4
Current Risk Management Liabilities	0.8	(0.6)	0.2
Long-term Risk Management Liabilities	—	—	—

Total Liabilities	0.8	(0.6)	0.2
Total MTM Derivative Contract Net Assets	$ 6.2	$ —	$ 6.2

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) All derivative contracts subject to a master netting arrangement or similar agreement are offset in the statement of financial position.

The tables below present the Registrants' activity of derivative risk management contracts:

Amount of Gain (Loss) Recognized on Risk Management Contracts Year Ended December 31, 2018

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Vertically Integrated Utilities Revenues	$ (10.4)	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	38.9	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	(1.9)	(8.2)	—	—	0.1
Purchased Electricity for Resale	8.6	—	7.6	0.8	—	—	—
Other Operation	1.7	0.4	0.2	0.2	0.3	0.2	0.2
Maintenance	1.9	0.4	0.4	0.2	0.4	0.2	0.2
Regulatory Assets (a)	27.9	(0.7)	(0.7)	7.1	24.9	(1.1)	(1.2)
Regulatory Liabilities (a)	222.7	(0.5)	135.5	11.6	—	37.3	11.9
Total Gain (Loss) on Risk Management Contracts	$ 291.3	$ (0.4)	$ 141.1	$ 11.7	$ 25.6	$ 36.6	$ 11.2

Amount of Gain (Loss) Recognized on Risk Management Contracts Year Ended December 31, 2017

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Vertically Integrated Utilities Revenues	$ 6.1	$ —	$ —	$ —	$ —	$ —	$ —
Generation & Marketing Revenues	42.8	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	0.6	5.3	—	—	0.1
Purchased Electricity for Resale	5.6	—	2.0	0.6	—	—	—
Other Operation	0.8	0.1	0.1	0.1	0.1	0.1	0.1
Maintenance	0.7	0.2	0.1	0.1	0.1	0.1	0.1
Regulatory Assets (a)	(29.4)	—	—	(7.4)	(22.0)	—	0.3
Regulatory Liabilities (a)	109.4	0.1	40.4	15.9	—	24.8	24.3
Total Gain (Loss) on Risk Management Contracts	$ 136.0	$ 0.4	$ 43.2	$ 14.6	$ (21.8)	$ 25.0	$ 24.9

Amount of Gain (Loss) Recognized on Risk Management Contracts Year Ended December 31, 2016

Location of Gain (Loss)	AEP	AEP Texas	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Vertically Integrated Utilities Revenues	$ 4.0	$ —	$ —	$ —	$ —	$ —	$ —
Transmission and Distribution Utilities Revenues	0.1	—	—	—	—	—	—
Generation & Marketing Revenues	59.4	—	—	—	—	—	—
Electric Generation, Transmission and Distribution Revenues	—	—	(0.6)	4.1	0.1	—	—
Sales to AEP Affiliates	—	—	2.1	5.8	—	—	—
Purchased Electricity for Resale	6.6	—	3.5	0.3	—	—	—
Other Operation	(1.6)	(0.4)	(0.1)	(0.1)	(0.3)	(0.1)	(0.3)
Maintenance	(1.8)	(0.4)	(0.4)	(0.1)	(0.4)	(0.2)	(0.2)
Regulatory Assets (a)	(117.4)	0.8	0.6	3.1	(127.7)	0.4	5.2
Regulatory Liabilities (a)	79.1	0.4	51.4	13.9	(15.2)	6.5	15.7
Total Gain (Loss) on Risk Management Contracts	$ 28.4	$ 0.4	$ 56.5	$ 27.0	$ (143.5)	$ 6.6	$ 20.4

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the statements of income on an accrual basis.

The accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, management designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on the statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the statements of income depending on the relevant facts and circumstances. Certain derivatives that economically hedge future commodity risk are recorded in the same expense line item on the statements of income as that of the associated risk. However, unrealized and some realized gains and losses in regulated jurisdictions for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for "Regulated Operations."

Accounting for Fair Value Hedging Strategies (Applies to AEP)

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk impacts Net Income during the period of change.

AEP records realized and unrealized gains or losses on interest rate swaps that are designated and qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on the statements of income.

The following table shows the impacts recognized on the balance sheets related to the hedged items in fair value hedging relationships:

	Carrying Amount of the Hedged Assets/(Liabilities)		Cumulative Amount of Fair Value Hedging Adjustment Included in the Carrying Amount of the Hedged Assets/(Liabilities)	
	December 31, 2018	**December 31, 2017**	**December 31, 2018**	**December 31, 2017**
	(in millions)			
Long-Term Debt (a)	$ (478.3)	$ (489.3)	$ 17.4	$ 6.1

(a) Amounts included on the balance sheets within Long-term Debt Due within One Year and Long-term Debt, respectively.

The pretax effects of fair value hedge accounting on income were as follows:

	Twelve Months Ended December 31,		
	2018	**2017**	**2016**
	(in millions)		
Gain (Loss) on Interest Rate Contracts:			
Gain (Loss) on Fair Value Hedging Instruments (a)	$ (11.3)	$ (4.8)	$ 1.6
Gain (Loss) on Fair Value Portion of Long-term Debt (a)	11.3	4.8	(1.6)

(a) Gain (Loss) is included in Interest Expense on the statements of income.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), the Registrants initially report the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the balance sheets until the period the hedged item affects Net Income.

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Total Revenues or Purchased Electricity for Resale on the statements of income or in Regulatory Assets or Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During the years ended 2018, 2017 and 2016, AEP applied cash flow hedging to outstanding power derivatives. During the years ended 2018, 2017 and 2016, the Registrant Subsidiaries did not apply cash flow hedging to outstanding power derivatives.

The Registrants reclassify gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During the years ended 2018, 2017 and 2016, AEP applied cash flow hedging to outstanding interest rate derivatives. During the years ended 2017 and 2016, the Registrant Subsidiaries did not apply cash flow hedging to outstanding interest rate derivatives. During the year ended 2018, SWEPCo applied cash flow hedging to outstanding interest rate derivatives and the other Registrant Subsidiaries did not.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Depreciation and Amortization expense on the statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During the years ended 2018, 2017 and 2016, the Registrants did not apply cash flow hedging to any outstanding foreign currency derivatives.

For details on effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets and the reasons for changes in cash flow hedges, see Note 3 - Comprehensive Income.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets were:

Impact of Cash Flow Hedges on AEP's Balance Sheets

	December 31, 2018		December 31, 2017	
	Commodity	Interest Rate	Commodity	Interest Rate
	(in millions)			
AOCI Gain (Loss) Net of Tax	$ (23.0)	$ (12.6)	$ (28.4)	$ (13.0)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	10.4	(1.1)	5.5	(0.8)

As of December 31, 2018 the maximum length of time that AEP is hedging its exposure to variability in future cash flows related to forecasted transactions is 180 months.

Impact of Cash Flow Hedges on the Registrant Subsidiaries' Balance Sheets

	December 31, 2018		December 31, 2017	
	Interest Rate			
Company	AOCI Gain (Loss) Net of Tax	Expected to be Reclassed to Net Income During the Next Twelve Months	AOCI Gain (Loss) Net of Tax	Expected to be Reclassed to Net Income During the Next Twelve Months
	(in millions)			
AEP Texas	$ (4.4)	$ (1.1)	$ (4.5)	$ (0.9)
APCo	1.8	0.9	2.2	0.7
I&M	(11.5)	(1.6)	(10.7)	(1.3)
OPCo	1.0	1.0	1.9	1.1
PSO	2.1	1.0	2.6	0.8
SWEPCo	(3.3)	(1.5)	(6.0)	(1.4)

The actual amounts reclassified from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes.

Credit Risk

Management mitigates credit risk in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. Management uses credit agency ratings and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

Master agreements are typically used to facilitate the netting of cash flows associated with a single counterparty and may include collateral requirements. Collateral requirements in the form of cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. Some master agreements include margining, which requires a counterparty to post cash or letters of credit in the event exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, master agreements allow for termination and liquidation of all positions in the event of a default including a failure or inability to post collateral when required.

Collateral Triggering Events

Credit Downgrade Triggers (Applies to AEP, APCo, I&M, PSO and SWEPCo)

A limited number of derivative contracts include collateral triggering events, which include a requirement to maintain certain credit ratings. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering events in contracts. The Registrants have not experienced a downgrade below a specified credit rating threshold that would require the posting of additional collateral. The Registrants had no derivative contracts with collateral triggering events in a net liability position as of December 31, 2018 and 2017.

Cross-Default Triggers (Applies to AEP, APCo, I&M and SWEPCo)

In addition, a majority of non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation that is $50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following tables represent: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount that the exposure has been reduced by cash collateral posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering contractual netting arrangements:

	December 31, 2018		
Company	Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
		(in millions)	
AEP	$ 225.5	$ 1.8	$ 181.0
APCo	0.9	—	—
I&M	0.5	—	—
SWEPCo	2.3	—	2.3

	December 31, 2017		
Company	Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
		(in millions)	
AEP	$ 243.6	$ 1.3	$ 223.1
APCo	0.6	—	0.5
I&M	0.4	—	0.4
SWEPCo	0.2	—	0.1

11. FAIR VALUE MEASUREMENTS

The disclosures in this note apply to all Registrants except AEPTCo unless indicated otherwise.

Fair Value Measurements of Long-term Debt (Applies to all Registrants)

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of Long-term Debt are summarized in the following table:

	December 31,			
	2018		2017	
Company	**Book Value**	**Fair Value**	**Book Value**	**Fair Value**
	(in millions)			
AEP	$ 23,346.7	$ 24,093.9	$ 21,173.3	$ 23,649.6
AEP Texas	3,881.3	3,964.6	3,649.3	3,964.8
AEPTCo	2,823.0	2,782.4	2,550.4	2,782.9
APCo	4,062.6	4,473.3	3,980.1	4,782.6
I&M	3,035.4	3,070.2	2,745.1	3,014.7
OPCo	1,716.6	1,919.7	1,719.3	2,064.3
PSO	1,287.0	1,361.9	1,286.5	1,457.1
SWEPCo	2,713.4	2,670.2	2,441.9	2,645.9

Fair Value Measurements of Other Temporary Investments (Applies to AEP)

Other Temporary Investments include marketable securities that management intends to hold for less than one year and investments by AEP's protected cell of EIS. See "Other Temporary Investments" section of Note 1 for additional information.

The following is a summary of Other Temporary Investments:

	December 31, 2018			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
	(in millions)			
Restricted Cash and Other Cash Deposits (a)	$ 230.6	$ —	$ —	$ 230.6
Fixed Income Securities – Mutual Funds (b)	106.6	—	(2.3)	104.3
Equity Securities – Mutual Funds	17.8	16.4	—	34.2
Total Other Temporary Investments	$ 355.0	$ 16.4	$ (2.3)	$ 369.1

	December 31, 2017			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Fair Value**
	(in millions)			
Restricted Cash and Other Cash Deposits (a)	$ 220.1	$ —	$ —	$ 220.1
Fixed Income Securities – Mutual Funds (b)	104.3	—	(1.4)	102.9
Equity Securities – Mutual Funds	17.0	19.7	—	36.7
Total Other Temporary Investments	$ 341.4	$ 19.7	$ (1.4)	$ 359.7

(a) Primarily represents amounts held for the repayment of debt.
(b) Primarily short and intermediate maturities which may be sold and do not contain maturity dates.

The following table provides the activity for fixed income and equity securities within Other Temporary Investments:

	Years Ended December 31, 2018	2017	2016
	(in millions)		
Proceeds from Investment Sales	$ —	$ —	$ —
Purchases of Investments	3.1	14.2	2.3
Gross Realized Gains on Investment Sales	—	—	—
Gross Realized Losses on Investment Sales	—	—	—

For details of the reasons for changes in Securities Available for Sale included in Accumulated Other Comprehensive Income (Loss) for the years ended December 31, 2018, 2017 and 2016, see Note 3 - Comprehensive Income.

Fair Value Measurements of Trust Assets for Decommissioning and Spent Nuclear Fuel Disposal (Applies to AEP and I&M)

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF are recorded at fair value. See "Nuclear Trust Funds" section of Note 1.

The following is a summary of nuclear trust fund investments:

	December 31, 2018			2017		
	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$ 22.5	$ —	$ —	$ 17.2	$ —	$ —
Fixed Income Securities:						
United States Government	996.1	26.7	(7.1)	981.2	29.7	(3.6)
Corporate Debt	52.4	1.1	(1.9)	58.7	3.8	(1.2)
State and Local Government	8.6	0.6	(0.2)	8.8	0.8	(0.2)
Subtotal Fixed Income Securities	1,057.1	28.4	(9.2)	1,048.7	34.3	(5.0)
Equity Securities – Domestic (a)	1,395.3	766.3	—	1,461.7	868.2	(75.5)
Spent Nuclear Fuel and Decommissioning Trusts	$ 2,474.9	$ 794.7	$ (9.2)	$ 2,527.6	$ 902.5	$ (80.5)

(a) Amount reported as Gross Unrealized Gains includes unrealized gains of $784 million and unrealized losses of $18 million. AEP adopted ASU 2016-01 during the first quarter of 2018 by means of a modified retrospective approach. Due to the adoption of the ASU, Other-Than-Temporary Impairments are no longer applicable to Equity Securities with readily determinable fair values.

The following table provides the securities activity within the decommissioning and SNF trusts:

	Years Ended December 31,		
	2018	2017	2016
	(in millions)		
Proceeds from Investment Sales	$ 2,010.0	$ 2,256.3	$ 2,957.7
Purchases of Investments	2,064.7	2,300.5	3,000.0
Gross Realized Gains on Investment Sales	47.5	200.7	46.1
Gross Realized Losses on Investment Sales	32.8	146.0	24.4

The base cost of fixed income securities was $1 billion and $1 billion as of December 31, 2018 and 2017, respectively. The base cost of equity securities was $629 million and $594 million as of December 31, 2018 and 2017, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of December 31, 2018 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 359.4
After 1 year through 5 years	358.9
After 5 years through 10 years	176.1
After 10 years	162.7
Total	$ 1,057.1

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

The following tables set forth, by level within the fair value hierarchy, the Registrants' financial assets and liabilities that were accounted for at fair value on a recurring basis. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments					
Restricted Cash and Other Cash Deposits (a)	$ 221.5	$ —	$ —	$ 9.1	$ 230.6
Fixed Income Securities – Mutual Funds	104.3	—	—	—	104.3
Equity Securities – Mutual Funds (b)	34.2	—	—	—	34.2
Total Other Temporary Investments	360.0	—	—	9.1	369.1
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	3.8	326.5	340.9	(288.5)	382.7
Cash Flow Hedges:					
Commodity Hedges (c)	—	24.1	12.7	(2.7)	34.1
Total Risk Management Assets	3.8	350.6	353.6	(291.2)	416.8
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	12.3	—	—	10.2	22.5
Fixed Income Securities:					
United States Government	—	996.1	—	—	996.1
Corporate Debt	—	52.4	—	—	52.4
State and Local Government	—	8.6	—	—	8.6
Subtotal Fixed Income Securities	—	1,057.1	—	—	1,057.1
Equity Securities – Domestic (b)	1,395.3	—	—	—	1,395.3
Total Spent Nuclear Fuel and Decommissioning Trusts	1,407.6	1,057.1	—	10.2	2,474.9
Total Assets	$ 1,771.4	$ 1,407.7	$ 353.6	$ (271.9)	$ 3,260.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 4.2	$ 327.0	$ 185.6	$ (274.7)	$ 242.1
Cash Flow Hedges:					
Commodity Hedges (c)	—	24.8	36.8	(2.7)	58.9
Fair Value Hedges	—	17.4	—	—	17.4
Total Risk Management Liabilities	$ 4.2	$ 369.2	$ 222.4	$ (277.4)	$ 318.4

AEP

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Other Temporary Investments					
Restricted Cash and Other Cash Deposits (a)	$ 183.2	$ —	$ —	$ 36.9	$ 220.1
Fixed Income Securities – Mutual Funds	102.9	—	—	—	102.9
Equity Securities – Mutual Funds (b)	36.7	—	—	—	36.7
Total Other Temporary Investments	322.8	—	—	36.9	359.7
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	3.9	391.2	274.1	(285.4)	383.8
Cash Flow Hedges:					
Commodity Hedges (c)	—	17.3	4.7	—	22.0
Fair Value Hedges	—	2.5	—	—	2.5
Total Risk Management Assets	3.9	411.0	278.8	(285.4)	408.3
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	7.5	—	—	9.7	17.2
Fixed Income Securities:					
United States Government	—	981.2	—	—	981.2
Corporate Debt	—	58.7	—	—	58.7
State and Local Government	—	8.8	—	—	8.8
Subtotal Fixed Income Securities	—	1,048.7	—	—	1,048.7
Equity Securities – Domestic (b)	1,461.7	—	—	—	1,461.7
Total Spent Nuclear Fuel and Decommissioning Trusts	1,469.2	1,048.7	—	9.7	2,527.6
Total Assets	$ 1,795.9	$ 1,459.7	$ 278.8	$ (238.8)	$ 3,295.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f)	$ 5.1	$ 392.5	$ 196.9	$ (285.0)	$ 309.5
Cash Flow Hedges:					
Commodity Hedges (c)	—	23.9	41.6	—	65.5
Fair Value Hedges	—	8.6	—	—	8.6
Total Risk Management Liabilities	$ 5.1	$ 425.0	$ 238.5	$ (285.0)	$ 383.6

AEP Texas

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 156.7	$ —	$ —	$ —	$ 156.7
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c)	$ —	$ 0.7	$ —	$ (0.5)	$ 0.2

December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 155.2	$ —	$ —	$ —	$ 155.2
Risk Management Assets					
Risk Management Commodity Contracts (c)	—	0.5	—	—	0.5
Total Assets	$ 155.2	$ 0.5	$ —	$ —	$ 155.7

APCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 25.6	$ —	$ —	$ —	$ 25.6
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	0.1	59.1	58.3	(59.4)	58.1
Total Assets	$ 25.7	$ 59.1	$ 58.3	$ (59.4)	$ 83.7
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ 0.2	$ 58.4	$ 0.5	$ (58.5)	$ 0.6

December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 16.3	$ —	$ —	$ —	$ 16.3
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	—	52.5	25.1	(51.6)	26.0
Total Assets	$ 16.3	$ 52.5	$ 25.1	$ (51.6)	$ 42.3
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 51.2	$ 0.4	$ (50.1)	$ 1.5

I&M

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 42.1	$ 10.3	$ (43.2)	$ 9.2
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	12.3	—	—	10.2	22.5
Fixed Income Securities:					
United States Government	—	996.1	—	—	996.1
Corporate Debt	—	52.4	—	—	52.4
State and Local Government	—	8.6	—	—	8.6
Subtotal Fixed Income Securities	—	1,057.1	—	—	1,057.1
Equity Securities – Domestic (b)	1,395.3	—	—	—	1,395.3
Total Spent Nuclear Fuel and Decommissioning Trusts	1,407.6	1,057.1	—	10.2	2,474.9
Total Assets	$ 1,407.6	$ 1,099.2	$ 10.3	$ (33.0)	$ 2,484.1
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ 0.1	$ 41.2	$ 1.4	$ (42.3)	$ 0.4

December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 39.4	$ 9.1	$ (40.2)	$ 8.3
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	7.5	—	—	9.7	17.2
Fixed Income Securities:					
United States Government	—	981.2	—	—	981.2
Corporate Debt	—	58.7	—	—	58.7
State and Local Government	—	8.8	—	—	8.8
Subtotal Fixed Income Securities	—	1,048.7	—	—	1,048.7
Equity Securities – Domestic (b)	1,461.7	—	—	—	1,461.7
Total Spent Nuclear Fuel and Decommissioning Trusts	1,469.2	1,048.7	—	9.7	2,527.6
Total Assets	$ 1,469.2	$ 1,088.1	$ 9.1	$ (30.5)	$ 2,535.9
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 47.6	$ 1.5	$ (45.5)	$ 3.6

OPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Restricted Cash for Securitized Funding	$ 27.6	$ —	$ —	$ —	$ 27.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.8	$ 99.4	$ (0.6)	$ 99.6

December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.6	$ —	$ —	$ 0.6
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 132.4	$ —	$ 132.4

PSO

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 10.8	$ (0.4)	$ 10.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.3	$ 1.3	$ (0.6)	$ 1.0

December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.2	$ 6.4	$ (0.2)	$ 6.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 0.2	$ (0.2)	$ —

SWEPCo

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 5.6	$ (0.8)	$ 4.8
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.4	$ 3.3	$ (1.1)	$ 2.6

December 31, 2017

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	$ —	$ 0.3	$ 6.7	$ (0.6)	$ 6.4
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ —	$ —	$ 0.8	$ (0.6)	$ 0.2

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or third-parties. Level 1 and Level 2 amounts primarily represent investments in money market funds.

(b) Amounts represent publicly traded equity securities and equity-based mutual funds.

(c) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."

(d) The December 31, 2018 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 2 matures $(4) million in 2019, $1 million in periods 2020-2022, $1 million in periods 2023-2024 and $1 million in periods 2025-2032; Level 3 matures $108 million in 2019, $37 million in periods 2020-2022, $23 million in periods 2023-2024 and $(12) million in periods 2025-2032. Risk management commodity contracts are substantially comprised of power contracts.

(e) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 1 amounts primarily represent investments in money market funds.

(f) The December 31, 2017 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $(1) million in 2018; Level 2 matures $(3) million in 2018 and $2 million in periods 2022-2023; Level 3 matures $59 million in 2018, $33 million in periods 2019-2021, $14 million in periods 2022-2023 and $(29) million in periods 2024-2032. Risk management commodity contracts are substantially comprised of power contracts.

(g) Substantially comprised of power contracts for the Registrant Subsidiaries.

There were no transfers between Level 1 and Level 2 during the years ended December 31, 2018, 2017 and 2016.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives classified as Level 3 in the fair value hierarchy:

Year Ended December 31, 2018	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2017	$ 40.3	$ 24.7	$ 7.6	$ (132.4)	$ 6.2	$ 5.9
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	148.9	104.1	14.2	1.8	18.1	(4.8)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (b)	9.8	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	15.7	—	—	—	—	—
Settlements	(214.0)	(127.9)	(21.3)	4.6	(24.3)	(2.1)
Transfers into Level 3 (d) (e)	15.8	—	—	—	—	—
Transfers out of Level 3 (e)	(1.6)	—	(0.3)	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	116.3	56.9	8.7	26.6	9.5	3.3
Balance as of December 31, 2018	$ 131.2	$ 57.8	$ 8.9	$ (99.4)	$ 9.5	$ 2.3

Year Ended December 31, 2017	AEP	APCo	I&M	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2016	$ 2.5	$ 1.4	$ 2.8	$ (119.0)	$ 0.7	$ 0.7
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	37.3	17.2	4.0	(1.4)	3.1	6.0
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (b)	33.6	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(18.8)	—	—	—	—	—
Settlements	(50.6)	(18.9)	(7.1)	7.4	(3.8)	(6.8)
Transfers into Level 3 (d) (e)	16.2	—	—	—	—	—
Transfers out of Level 3 (e)	(10.1)	—	—	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	30.2	25.0	7.9	(19.4)	6.2	6.0
Balance as of December 31, 2017	$ 40.3	$ 24.7	$ 7.6	$ (132.4)	$ 6.2	$ 5.9

Year Ended December 31, 2016	AEP	APCo (a)	I&M (a)	OPCo	PSO	SWEPCo
			(in millions)			
Balance as of December 31, 2015	$ 146.9	$ 11.7	$ 4.3	$ 15.9	$ 0.6	$ 0.8
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (b) (c)	42.8	25.6	7.1	(3.0)	(1.0)	7.7
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (b)	26.1	—	—	—	—	—
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(23.0)	—	—	—	—	—
Settlements	(71.4)	(37.5)	(11.1)	6.2	0.4	(8.4)
Transfers into Level 3 (d) (e)	13.3	—	—	—	—	—
Transfers out of Level 3 (e)	(2.6)	0.1	0.1	—	—	—
Changes in Fair Value Allocated to Regulated Jurisdictions (f)	(129.6)	1.5	2.4	(138.1)	0.7	0.6
Balance as of December 31, 2016	$ 2.5	$ 1.4	$ 2.8	$ (119.0)	$ 0.7	$ 0.7

(a) Includes both affiliated and nonaffiliated transactions.
(b) Included in revenues on the statements of income.
(c) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory assets/liabilities or accounts payable.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

Significant Unobservable Inputs
December 31, 2018

AEP

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	**Liabilities**	**Technique**	**Input**	**Low**	**High**	**Weighted Average**
	(in millions)						
Energy Contracts	$ 257.1	$ 212.5	Discounted Cash Flow	Forward Market Price (a)	$ (0.05)	$ 176.57	$ 33.07
Natural Gas Contracts	—	2.5	Discounted Cash Flow	Forward Market Price (b)	2.18	3.54	2.47
FTRs	96.5	7.4	Discounted Cash Flow	Forward Market Price (a)	(11.68)	17.79	1.09
Total	$ 353.6	$ 222.4					

Significant Unobservable Inputs
December 31, 2017

AEP

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	**Liabilities**	**Technique**	**Input**	**Low**	**High**	**Weighted Average**
	(in millions)						
Energy Contracts	$ 225.1	$ 233.7	Discounted Cash Flow	Forward Market Price (a)	$ (0.05)	$ 263.00	$ 36.32
Natural Gas Contracts	—	0.2	Discounted Cash Flow	Forward Market Price (b)	2.37	2.96	2.62
FTRs	53.7	4.6	Discounted Cash Flow	Forward Market Price (a)	(55.62)	54.88	0.41
Total	$ 278.8	$ 238.5					

Significant Unobservable Inputs
December 31, 2018

APCo

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 2.4	$ 0.5	Discounted Cash Flow	Forward Market Price	$ 16.82	$ 62.65	$ 37.00
FTRs	55.9	—	Discounted Cash Flow	Forward Market Price	0.10	15.16	3.27
Total	$ 58.3	$ 0.5					

Significant Unobservable Inputs
December 31, 2017

APCo

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 0.8	$ 0.4	Discounted Cash Flow	Forward Market Price	$ 20.52	$ 195.00	$ 33.80
FTRs	24.3	—	Discounted Cash Flow	Forward Market Price	(0.36)	7.15	1.62
Total	$ 25.1	$ 0.4					

Significant Unobservable Inputs
December 31, 2018

I&M

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 1.4	$ 0.9	Discounted Cash Flow	Forward Market Price	$ 16.82	$ 62.65	$ 37.00
FTRs	8.9	0.5	Discounted Cash Flow	Forward Market Price	(2.11)	6.21	1.06
Total	$ 10.3	$ 1.4					

Significant Unobservable Inputs
December 31, 2017

I&M

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ 0.5	$ 0.3	Discounted Cash Flow	Forward Market Price	$ 20.52	$ 195.00	$ 33.80
FTRs	8.6	1.2	Discounted Cash Flow	Forward Market Price	(0.36)	5.75	0.86
Total	$ 9.1	$ 1.5					

Significant Unobservable Inputs
December 31, 2018

OPCo

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ —	$ 99.4	Discounted Cash Flow	Forward Market Price	$ 26.29	$ 62.74	$ 42.50

Significant Unobservable Inputs
December 31, 2017

OPCo

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
Energy Contracts	$ —	$ 132.4	Discounted Cash Flow	Forward Market Price	$ 30.52	$ 170.43	$ 44.62

Significant Unobservable Inputs
December 31, 2018

PSO

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
FTRs	$ 10.8	$ 1.3	Discounted Cash Flow	Forward Market Price	$ (11.68)	$ 10.30	$ (1.40)

Significant Unobservable Inputs
December 31, 2017

PSO

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average
	(in millions)						
FTRs	$ 6.4	$ 0.2	Discounted Cash Flow	Forward Market Price	$ (6.62)	$ 1.41	$ (0.76)

Significant Unobservable Inputs
December 31, 2018

SWEPCo

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	**Liabilities**	**Technique**	**Input**	**Low**	**High**	**Weighted Average**
	(in millions)						
Natural Gas Contracts	$ —	$ 2.5	Discounted Cash Flow	Forward Market Price (b)	$ 2.18	$ 3.54	$ 2.47
FTRs	5.6	0.8	Discounted Cash Flow	Forward Market Price (a)	(11.68)	10.30	(1.40)
Total	$ 5.6	$ 3.3					

Significant Unobservable Inputs
December 31, 2017

SWEPCo

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	**Liabilities**	**Technique**	**Input**	**Low**	**High**	**Weighted Average**
	(in millions)						
Natural Gas Contracts	$ —	$ 0.2	Discounted Cash Flow	Forward Market Price (b)	$ 2.37	$ 2.96	$ 2.62
FTRs	6.7	0.6	Discounted Cash Flow	Forward Market Price (a)	(6.62)	1.41	(0.76)
Total	$ 6.7	$ 0.8					

(a) Represents market prices in dollars per MWh.
(b) Represents market prices in dollars per MMBtu.

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts, Natural Gas Contracts and FTRs for the Registrants as of December 31, 2018 and 2017:

Sensitivity of Fair Value Measurements

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)

12. INCOME TAXES

The disclosures in this note apply to all Registrants unless indicated otherwise.

Federal Tax Reform and Legislation

In December 2017, Tax Reform legislation was signed into law. Tax Reform includes significant changes to the Internal Revenue Code of 1986, as amended, including lowering the corporate federal income tax rate from 35% to 21%. As a result of this rate change, the Registrants' deferred tax assets and liabilities were remeasured using the newly enacted rate of 21% in December 2017. In response to Tax Reform, the SEC staff issued Staff Accounting Bulletin 118 (SAB 118) in December 2017. SAB 118 provided for up to a one year period (the measurement period) in which to complete the required analyses and accounting required by Tax Reform.

During 2017, AEP recorded provisional amounts for the income tax effects of Tax Reform. Throughout 2018, AEP continued to assess the impacts of legislative changes in the tax code as well as interpretative changes of the tax code. The measurement period adjustments recorded during 2018 were immaterial.

The measurement period under SAB 118 ended in December 2018. However, Tax Reform uncertainties still remain and AEP will continue to monitor income tax effects that may change as a result of future legislation and further interpretation of Tax Reform based on proposed U.S. Treasury regulations and guidance from the IRS and state tax authorities.

Federal Legislation

The IRS has proposed new regulations that provide guidance regarding the additional first-year depreciation deduction under Section 168(k). The proposed regulations reflect changes as a result of Tax Reform and affect taxpayers with qualified depreciable property acquired and placed in service after September 27, 2017. Generally, AEP's regulated utilities will not be eligible for any bonus depreciation for property acquired and placed in service after January 1, 2018 and AEP's competitive businesses will be eligible for 100% expensing. However, for self-constructed property and other property placed in service in 2018 for which construction began prior to January 1, 2018, taxpayers are required to evaluate the contractual terms to determine if these additions qualify for 100% expensing under Tax Reform or 50% bonus depreciation as provided under prior tax law.

During the fourth quarter of 2018, the IRS proposed new regulations that reflect changes as a result of Tax Reform concerning potential limitations on the deduction of business interest expense. These regulations require an allocation of net interest expense between regulated and competitive businesses within the consolidated tax return. This allocation is based upon net tax basis, and the proposed regulations provide a de minimis test under which all interest is deductible if less than 10% is allocable to the competitive businesses. Management continues to review and evaluate the proposed regulations and at this time expect to be able to deduct materially all business interest expense under this de minimis provision.

Section 162(m) of the Internal Revenue Code generally limits the amount of compensation a company can deduct annually to $1 million for certain executive officers. The exemption from Section 162(m)'s deduction limit for performance-based compensation was repealed by Tax Reform, effective for taxable years ending after December 31, 2017. Management continues to evaluate whether any of its compensation plans qualify for transitional relief, such that payments made pursuant to these plans might be deductible.

Status of Tax Reform Regulatory Proceedings

For AEP's various regulatory jurisdictions where the regulatory effects of Tax Reform proceedings have not been fully resolved, the table below summarizes the current status. See Note 4 - Rate Matters for additional information.

Registrant (Jurisdiction)	Change in Tax Rate	Excess ADIT Subject to Normalization Requirements	Excess ADIT Not Subject to Normalization Requirements
AEP Texas (Texas-Distribution)	Order Issued	Order Issued	Order Issued – Partial (a)
AEP Texas (Texas-Transmission)	Order Issued	To be addressed in a later filing	To be addressed in a later filing
APCo (Virginia)	Legislation Enacted – Case Pending (b)	Legislation Enacted – Case Pending (b)	Order Issued – Partial; Separate Case Pending (c)
I&M (Michigan)	Order Issued	Case Pending	Case Pending
SWEPCo (Louisiana)	Case Pending – Rates Implemented (d)	Case Pending – Rates Implemented (d)	Case Pending – Rates Implemented (d)
SWEPCo (Texas)	Order Issued	To be addressed in a later filing	To be addressed in a later filing
PJM FERC Transmission	Settlement Approved (e)	Settlement Approved (e)	Settlement Approved (e)
SPP FERC Transmission	To be addressed in a later filing	To be addressed in a later filing	To be addressed in a later filing

(a) A portion of the Excess ADIT that is not subject to rate normalization requirements is to be addressed in a later filing.
(b) Legislation has been issued for a blanket amount that is subject to true-up and final commission approval.
(c) In October 2018, the Virginia SCC issued an order approving APCo's request to refund a portion of the Excess ADIT that is not subject to rate normalization requirements to customers. The remainder is to be addressed in a separate pending case.
(d) Rates have been implemented through a filed formula rate plan that is subject to true-up and final commission approval.
(e) An ALJ has approved a settlement. The settlement is subject to final FERC ruling.

Income Tax Expense (Benefit)

The details of the Registrants' Income Tax Expense (Benefit) before discontinued operations as reported are as follows:

Year Ended December 31, 2018	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Federal:								
Current	$ (31.7)	$ 37.0	$ (14.2)	$ (31.9)	$ 60.9	$ 55.6	$ 35.6	$ 18.3
Deferred	112.8	(16.4)	82.3	(24.6)	(44.1)	(36.9)	(34.7)	(0.5)
Deferred Investment Tax Credits	9.2	(1.5)	—	0.1	(4.7)	—	(2.0)	(1.4)
Total Federal	90.3	19.1	68.1	(56.4)	12.1	18.7	(1.1)	16.4
State and Local:								
Current	30.8	1.8	(0.6)	3.7	15.8	4.6	(0.2)	2.3
Deferred	(8.5)	(0.1)	16.6	7.8	1.2	0.7	3.6	1.7
Deferred Investment Tax Credits	2.7	—	—	—	—	—	2.7	—
Total State and Local	25.0	1.7	16.0	11.5	17.0	5.3	6.1	4.0
Income Tax Expense (Benefit) Before Discontinued Operations	$ 115.3	$ 20.8	$ 84.1	$ (44.9)	$ 29.1	$ 24.0	$ 5.0	$ 20.4

Year Ended December 31, 2017	AEP	AEP Texas	AEPTCo (a)	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Federal:								
Current	$ (4.0)	$ (85.7)	$ (130.4)	$ 15.3	$ (106.5)	$ 11.2	$ (77.1)	$ (30.1)
Deferred	856.6	63.3	254.8	166.9	202.1	141.3	122.7	84.8
Deferred Investment Tax Credits	48.6	(1.6)	—	(0.1)	(4.7)	—	(1.6)	(1.4)
Total Federal	901.2	(24.0)	124.4	182.1	90.9	152.5	44.0	53.3
State and Local:								
Current	16.0	0.6	1.1	(1.4)	(8.1)	0.2	(0.2)	(0.9)
Deferred	44.9	—	16.7	4.6	(1.4)	6.6	2.0	(4.3)
Deferred Investment Tax Credits	7.6	—	—	—	—	—	4.3	—
Total State and Local	68.5	0.6	17.8	3.2	(9.5)	6.8	6.1	(5.2)
Income Tax Expense (Benefit) Before Discontinued Operations	$ 969.7	$ (23.4)	$ 142.2	$ 185.3	$ 81.4	$ 159.3	$ 50.1	$ 48.1

Year Ended December 31, 2016	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Federal:								
Current	$ (30.7)	$ 40.9	$ (129.4)	$ 64.1	$ (44.8)	$ 178.8	$ (28.0)	$ (96.7)
Deferred	(28.8)	29.9	205.9	125.8	104.9	(40.8)	77.2	172.6
Deferred Investment Tax Credits	17.6	(1.7)	—	(0.1)	3.8	—	(1.4)	(1.2)
Total Federal	(41.9)	69.1	76.5	189.8	63.9	138.0	47.8	74.7
State and Local:								
Current	(10.5)	(8.8)	0.4	4.4	3.4	4.2	(1.9)	(12.6)
Deferred	(21.2)	(0.4)	17.2	4.9	0.2	1.6	5.3	(10.0)
Deferred Investment Tax Credits	(0.1)	—	—	—	—	—	3.2	—
Total State and Local	(31.8)	(9.2)	17.6	9.3	3.6	5.8	6.6	(22.6)
Income Tax Expense (Benefit) Before Discontinued Operations	$ (73.7)	$ 59.9	$ 94.1	$ 199.1	$ 67.5	$ 143.8	$ 54.4	$ 52.1

(a) The amounts presented reflect the revisions made to AEPTCo's previously issued financial statements. See "Revisions to Previously Issued Financial Statements" section of Note 1 for additional information.

The following are reconciliations for the Registrants between the federal income taxes computed by multiplying pretax income by the federal statutory tax rate and the income taxes reported:

AEP	Years Ended December 31, 2018	2017	2016
	(in millions)		
Net Income	$ 1,931.3	$ 1,928.9	$ 618.0
Less: Equity Earnings – Dolet Hills	(2.7)	—	—
Discontinued Operations (Net of Income Tax of $0, $0 and $0 in 2018, 2017 and 2016, Respectively)	—	—	2.5
Income Tax Expense (Benefit) Before Discontinued Operations	115.3	969.7	(73.7)
Pretax Income	$ 2,043.9	$ 2,898.6	$ 546.8
Income Taxes on Pretax Income at Statutory Rate (21%, 35% and 35% in 2018, 2017 and 2016, Respectively)	$ 429.2	$ 1,014.5	$ 191.4
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	24.4	60.2	41.7
Investment Tax Credit Amortization	(20.2)	(18.8)	(12.3)
State and Local Income Taxes, Net	19.7	54.7	(20.7)
Removal Costs	(19.8)	(32.7)	(39.8)
AFUDC	(29.4)	(37.4)	(44.8)
Valuation Allowance	—	(1.8)	(128.3)
U.K. Windfall Tax	—	—	(12.9)
Tax Reform Adjustments	(10.9)	(26.7)	—
Tax Adjustments	—	(35.8)	(43.9)
Tax Reform Excess ADIT Reversal	(257.2)	—	—
Other	(20.5)	(6.5)	(4.1)
Income Tax Expense (Benefit) Before Discontinued Operations	$ 115.3	$ 969.7	$ (73.7)
Effective Income Tax Rate	5.6 %	33.5 %	(13.5) %

AEP Texas	Years Ended December 31, 2018	2017	2016
	(in millions)		
Net Income	$ 211.3	$ 310.5	$ 146.6
Discontinued Operations (Net of Income Tax of $0, $0 and $27.6 in 2018, 2017 and 2016, Respectively)	—	—	48.8
Income Tax Expense (Benefit)	20.8	(23.4)	59.9
Pretax Income	$ 232.1	$ 287.1	$ 255.3
Income Taxes on Pretax Income at Statutory Rate (21%, 35% and 35% in 2018, 2017 and 2016, Respectively)	$ 48.7	$ 100.5	$ 89.4
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
State and Local Income Taxes, Net	1.3	0.4	(6.0)
AFUDC	(4.2)	(3.9)	(3.2)
Parent Company Loss Benefit	(3.1)	—	(2.5)
Tax Reform Adjustments	(11.0)	(117.4)	—
Tax Adjustments	—	(4.2)	(4.9)
U.K. Windfall Tax	—	—	(12.9)
Tax Reform Excess ADIT Reversal	(11.8)	—	—
Other	0.9	1.2	—
Income Tax Expense (Benefit) Before Discontinued Operations	$ 20.8	$ (23.4)	$ 59.9
Effective Income Tax Rate	9.0 %	(8.2) %	23.5 %

AEPTCo

	Years Ended December 31,		
	2018	**2017 (a)**	**2016**
		(in millions)	
Net Income	$ 315.9	$ 270.7	$ 192.7
Income Tax Expense	84.1	142.2	94.1
Pretax Income	$ 400.0	$ 412.9	$ 286.8
Income Taxes on Pretax Income at Statutory Rate (21%, 35% and 35% in 2018, 2017 and 2016, Respectively)	$ 84.0	$ 144.5	$ 100.4
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
AFUDC	(14.1)	(17.0)	(18.3)
State and Local Income Taxes, Net	12.6	13.1	11.4
Tax Reform Adjustments	—	0.6	—
Other	1.6	1.0	0.6
Income Tax Expense	$ 84.1	$ 142.2	$ 94.1
Effective Income Tax Rate	21.0 %	34.4 %	32.8 %

(a) The amounts presented reflect the revisions made to AEPTCo's previously issued financial statements. See "Revisions to Previously Issued Financial Statements" section of Note 1 for additional information.

APCo

	Years Ended December 31,		
	2018	**2017**	**2016**
		(in millions)	
Net Income	$ 367.8	$ 331.3	$ 369.1
Income Tax Expense (Benefit)	(44.9)	185.3	199.1
Pretax Income	$ 322.9	$ 516.6	$ 568.2
Income Taxes on Pretax Income at Statutory Rate (21%, 35% and 35% in 2018, 2017 and 2016, Respectively)	$ 67.8	$ 180.8	$ 198.9
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	8.5	18.0	19.3
State and Local Income Taxes, Net	9.1	3.5	6.0
Removal Costs	(9.6)	(12.4)	(12.0)
AFUDC	(4.3)	(5.0)	(6.1)
Tax Reform Adjustments	0.1	4.3	—
Tax Reform Excess ADIT Reversal	(108.5)	—	—
Other	(8.0)	(3.9)	(7.0)
Income Tax Expense (Benefit)	$ (44.9)	$ 185.3	$ 199.1
Effective Income Tax Rate	(13.9) %	35.9 %	35.0 %

I&M

	Years Ended December 31, 2018	2017	2016
	(in millions)		
Net Income	$ 261.3	$ 186.7	$ 239.9
Income Tax Expense	29.1	81.4	67.5
Pretax Income	$ 290.4	$ 268.1	$ 307.4
Income Taxes on Pretax Income at Statutory Rate (21%, 35% and 35% in 2018, 2017 and 2016, Respectively)	$ 61.0	$ 93.8	$ 107.6
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	(0.7)	11.4	6.7
Investment Tax Credit Amortization	(4.7)	(4.7)	(4.7)
State and Local Income Taxes, Net	13.4	(1.0)	2.4
Removal Costs	(8.0)	(13.3)	(21.3)
AFUDC	(2.5)	(5.6)	(7.3)
Tax Adjustments	—	2.7	(14.2)
Tax Reform Adjustments	—	(2.9)	—
Tax Reform Excess ADIT Reversal	(25.8)	—	—
Other	(3.6)	1.0	(1.7)
Income Tax Expense	$ 29.1	$ 81.4	$ 67.5
Effective Income Tax Rate	10.0 %	30.4 %	22.0 %

OPCo

	Years Ended December 31, 2018	2017	2016
	(in millions)		
Net Income	$ 325.5	$ 323.9	$ 282.2
Income Tax Expense	24.0	159.3	143.8
Pretax Income	$ 349.5	$ 483.2	$ 426.0
Income Taxes on Pretax Income at Statutory Rate (21%, 35% and 35% in 2018, 2017 and 2016, Respectively)	$ 73.4	$ 169.1	$ 149.1
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	2.6	7.6	7.1
State and Local Income Taxes, Net	4.2	4.4	3.8
Tax Reform Adjustments	—	(14.4)	—
Tax Reform Excess ADIT Reversal	(51.0)	—	—
Parent Company Loss Benefit	(5.5)	(0.2)	(7.2)
Other	0.3	(7.2)	(9.0)
Income Tax Expense	$ 24.0	$ 159.3	$ 143.8
Effective Income Tax Rate	6.9 %	33.0 %	33.8 %

PSO	Years Ended December 31,		
	2018	**2017**	**2016**
		(in millions)	
Net Income	$ 83.2	$ 72.0	$ 100.0
Income Tax Expense	5.0	50.1	54.4
Pretax Income	$ 88.2	$ 122.1	$ 154.4
Income Taxes on Pretax Income at Statutory Rate (21%, 35% and 35% in 2018, 2017 and 2016, Respectively)	$ 18.5	$ 42.7	$ 54.0
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	1.0	0.3	0.8
Investment Tax Credit Amortization	(1.7)	(1.6)	(1.4)
Parent Company Loss Benefit	(1.4)	—	—
State and Local Income Taxes, Net	4.8	4.0	4.2
Tax Reform Adjustments	—	2.8	—
Tax Reform Excess ADIT Reversal	(15.5)	—	—
Other	(0.7)	1.9	(3.2)
Income Tax Expense	$ 5.0	$ 50.1	$ 54.4
Effective Income Tax Rate	5.7 %	41.0 %	35.2 %

SWEPCo	Years Ended December 31,		
	2018	**2017**	**2016**
		(in millions)	
Net Income	$ 152.2	$ 137.5	$ 169.7
Less: Equity Earnings – Dolet Hills	(2.7)	—	—
Income Tax Expense	20.4	48.1	52.1
Pretax Income	$ 169.9	$ 185.6	$ 221.8
Income Taxes on Pretax Income at Statutory Rate (21%, 35% and 35% in 2018, 2017 and 2016, Respectively)	$ 35.7	$ 65.0	$ 77.6
Increase (Decrease) in Income Taxes Resulting from the Following Items:			
Depreciation	3.4	1.9	3.2
Depletion	(3.2)	(5.7)	(5.5)
State and Local Income Taxes, Net	3.2	(2.3)	(14.7)
AFUDC	(1.3)	(0.9)	(3.9)
Tax Adjustments	—	(9.9)	(0.9)
Tax Reform Adjustments	—	(0.4)	—
Tax Reform Excess ADIT Reversal	(16.0)	—	—
Other	(1.4)	0.4	(3.7)
Income Tax Expense	$ 20.4	$ 48.1	$ 52.1
Effective Income Tax Rate	12.0 %	25.9 %	23.5 %

Net Deferred Tax Liability

The following tables show elements of the net deferred tax liability and significant temporary differences for each Registrant:

AEP	**December 31, 2018**	**December 31, 2017**
	(in millions)	
Deferred Tax Assets	$ 2,750.8	$ 3,504.6
Deferred Tax Liabilities	(9,837.3)	(10,318.5)
Net Deferred Tax Liabilities	$ (7,086.5)	$ (6,813.9)
Property Related Temporary Differences	$ (6,224.8)	$ (5,680.6)
Amounts Due to Customers for Future Federal Income Taxes	1,117.1	1,064.8
Deferred State Income Taxes (a)	(859.9)	(1,124.4)
Securitized Assets	(186.6)	(257.7)
Regulatory Assets	(454.1)	(500.3)
Deferred Income Taxes on Other Comprehensive Loss	32.0	25.7
Accrued Nuclear Decommissioning	(453.7)	(457.0)
Net Operating Loss Carryforward	78.3	86.6
Tax Credit Carryforward	113.7	174.7
Investment in Partnership	(300.5)	(222.0)
All Other, Net	52.0	76.3
Net Deferred Tax Liabilities	$ (7,086.5)	$ (6,813.9)

(a) In 2018, AEP recorded a $233 million correction related to the accounting for the impact of Tax Reform in 2017. The correction resulted in a decrease in Net Deferred Tax Liabilities with an offsetting increase to Regulatory Liabilities and Deferred Investment Tax Credits as of December 31, 2018. Management concluded the misstatement was not material to the 2017 financial statements or the financial statements of any of the interim periods in 2018.

AEP Texas	**December 31, 2018**	**December 31, 2017**
	(in millions)	
Deferred Tax Assets	$ 208.1	$ 221.0
Deferred Tax Liabilities	(1,121.2)	(1,134.1)
Net Deferred Tax Liabilities	$ (913.1)	$ (913.1)
Property Related Temporary Differences	$ (836.3)	$ (791.5)
Amounts Due to Customers for Future Federal Income Taxes	140.6	140.9
Deferred State Income Taxes	(27.1)	(27.5)
Regulatory Assets	(53.9)	(36.4)
Securitized Transition Assets	(134.7)	(190.5)
Deferred Income Taxes on Other Comprehensive Loss	4.0	4.1
Deferred Revenues	4.6	10.9
All Other, Net	(10.3)	(23.1)
Net Deferred Tax Liabilities	$ (913.1)	$ (913.1)

AEPTCo	December 31, 2018	December 31, 2017 (a)
	(in millions)	
Deferred Tax Assets	$ 142.9	$ 163.0
Deferred Tax Liabilities	(847.3)	(763.4)
Net Deferred Tax Liabilities	$ (704.4)	$ (600.4)
Property Related Temporary Differences	$ (755.0)	$ (653.4)
Amounts Due to Customers for Future Federal Income Taxes	101.6	89.7
Deferred State Income Taxes (b)	(51.9)	(77.4)
Deferred Federal Income Taxes on Deferred State Income Taxes	—	16.3
Net Operating Loss Carryforward	13.4	16.8
Tax Credit Carryforward	—	0.3
All Other, Net	(12.5)	7.3
Net Deferred Tax Liabilities	$ (704.4)	$ (600.4)

(a) The amounts presented reflect the revisions made to AEPTCo's previously issued financial statements. See the "Revisions to Previously Issued Financial Statements" section of Note 1 for additional information.
(b) In 2018, AEPTCo recorded a $21 million correction related to the accounting for the impact of Tax Reform in 2017. The correction resulted in a decrease in Net Deferred Tax Liabilities with an offsetting increase to Regulatory Liabilities and Deferred Investment Tax Credits as of December 31, 2018. Management concluded the misstatement was not material to the 2017 financial statements or the financial statements of any of the interim periods in 2018.

APCo	December 31, 2018	December 31, 2017
	(in millions)	
Deferred Tax Assets	$ 475.2	$ 614.4
Deferred Tax Liabilities	(2,101.0)	(2,180.1)
Net Deferred Tax Liabilities	$ (1,625.8)	$ (1,565.7)
Property Related Temporary Differences	$ (1,393.6)	$ (1,308.2)
Amounts Due to Customers for Future Federal Income Taxes	224.2	228.0
Deferred State Income Taxes (a)	(280.3)	(335.7)
Regulatory Assets	(73.8)	(83.9)
Securitized Assets	(54.3)	(59.3)
Deferred Income Taxes on Other Comprehensive Loss	1.3	(0.4)
Tax Credit Carryforward	0.2	16.6
All Other, Net	(49.5)	(22.8)
Net Deferred Tax Liabilities	$ (1,625.8)	$ (1,565.7)

(a) In 2018, APCo recorded a $51 million correction related to the accounting for the impact of Tax Reform in 2017. The correction resulted in a decrease in Net Deferred Tax Liabilities with an offsetting increase to Regulatory Liabilities and Deferred Investment Tax Credits as of December 31, 2018. Management concluded the misstatement was not material to the 2017 financial statements or the financial statements of any of the interim periods in 2018.

I&M

	December 31, 2018	December 31, 2017
	(in millions)	
Deferred Tax Assets	$ 771.6	$ 1,096.4
Deferred Tax Liabilities	(1,719.6)	(2,050.2)
Net Deferred Tax Liabilities	$ (948.0)	$ (953.8)
Property Related Temporary Differences	$ (445.0)	$ (403.0)
Amounts Due to Customers for Future Federal Income Taxes	142.0	137.6
Deferred State Income Taxes (a)	(139.7)	(180.6)
Deferred Income Taxes on Other Comprehensive Loss	3.7	3.9
Accrued Nuclear Decommissioning	(453.7)	(457.0)
Regulatory Assets	(31.9)	(43.8)
Net Operating Loss Carryforward	0.2	1.6
All Other, Net	(23.6)	(12.5)
Net Deferred Tax Liabilities	$ (948.0)	$ (953.8)

(a) In 2018, I&M recorded a $48 million correction related to the accounting for the impact of Tax Reform in 2017. The correction resulted in a decrease in Net Deferred Tax Liabilities with an offsetting increase to Regulatory Liabilities and Deferred Investment Tax Credits as of December 31, 2018. Management concluded the misstatement was not material to the 2017 financial statements or the financial statements of any of the interim periods in 2018.

OPCo

	December 31, 2018	December 31, 2017
	(in millions)	
Deferred Tax Assets	$ 209.0	$ 286.0
Deferred Tax Liabilities	(972.3)	(1,048.9)
Net Deferred Tax Liabilities	$ (763.3)	$ (762.9)
Property Related Temporary Differences	$ (826.9)	$ (761.2)
Amounts Due to Customers for Future Federal Income Taxes	130.9	127.3
Deferred State Income Taxes	(26.8)	(41.7)
Regulatory Assets	(55.0)	(107.7)
Deferred Income Taxes on Other Comprehensive Loss	(0.3)	(0.6)
Deferred Fuel and Purchased Power	(1.6)	(24.5)
All Other, Net	16.4	45.5
Net Deferred Tax Liabilities	$ (763.3)	$ (762.9)

PSO

	December 31, 2018	December 31, 2017
	(in millions)	
Deferred Tax Assets	$ 229.6	$ 269.2
Deferred Tax Liabilities	(837.4)	(911.2)
Net Deferred Tax Liabilities	$ (607.8)	$ (642.0)
Property Related Temporary Differences	$ (609.4)	$ (623.8)
Amounts Due to Customers for Future Federal Income Taxes	107.1	111.6
Deferred State Income Taxes (a)	(103.8)	(142.7)
Regulatory Assets	(32.3)	(34.4)
Deferred Income Taxes on Other Comprehensive Loss	(0.6)	(0.8)
Deferred Federal Income Taxes on Deferred State Income Taxes	—	33.5
Net Operating Loss Carryforward	16.4	23.1
Tax Credit Carryforward	—	0.7
All Other, Net	14.8	(9.2)
Net Deferred Tax Liabilities	$ (607.8)	$ (642.0)

(a) In 2018, PSO recorded a $33 million correction related to the accounting for the impact of Tax Reform in 2017. The correction resulted in a decrease in Net Deferred Tax Liabilities with an offsetting increase to Regulatory Liabilities and Deferred Investment Tax Credits as of December 31, 2018. Management concluded the misstatement was not material to the 2017 financial statements or the financial statements of any of the interim periods in 2018.

SWEPCo

	December 31, 2018	December 31, 2017
	(in millions)	
Deferred Tax Assets	$ 317.4	$ 349.4
Deferred Tax Liabilities	(1,220.2)	(1,267.1)
Net Deferred Tax Liabilities	$ (902.8)	$ (917.7)
Property Related Temporary Differences	$ (929.1)	$ (908.8)
Amounts Due to Customers for Future Federal Income Taxes	145.8	135.8
Deferred State Income Taxes (a)	(156.0)	(189.2)
Regulatory Assets	(30.8)	(30.8)
Deferred Income Taxes on Other Comprehensive Loss	1.4	1.3
Capital/Impairment Loss - Turk Plant	15.8	17.4
Net Operating Loss Carryforward	36.2	38.7
Tax Credit Carryforward	—	0.8
All Other, Net	13.9	17.1
Net Deferred Tax Liabilities	$ (902.8)	$ (917.7)

(a) In 2018, SWEPCo recorded a $38 million correction related to the accounting for the impact of Tax Reform in 2017. The correction resulted in a decrease in Net Deferred Tax Liabilities with an offsetting increase to Regulatory Liabilities and Deferred Investment Tax Credits as of December 31, 2018. Management concluded the misstatement was not material to the 2017 financial statements or the financial statements of any of the interim periods in 2018.

AEP System Tax Allocation Agreement

AEP and subsidiaries join in the filing of a consolidated federal income tax return. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The consolidated net operating loss of the AEP System is allocated to each company in the consolidated group with taxable losses. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the allocation of the consolidated AEP System net operating loss, the loss of the Parent and tax credits, the method of allocation reflects a separate return result for each company in the consolidated group.

Valuation Allowance

AEP assesses the available positive and negative evidence to estimate whether sufficient future taxable income of the appropriate tax character will be generated to realize the benefits of existing deferred tax assets. When the evaluation of the evidence indicates that AEP will not be able to realize the benefits of existing deferred tax assets, a valuation allowance is recorded to reduce existing deferred tax assets to the net realizable amount. Objective negative evidence evaluated includes whether AEP has a history of recognizing income of the character which can be offset by loss carryforwards. Other objective negative evidence evaluated is the impact recently enacted federal tax legislation will have on future taxable income and on AEP's ability to benefit from the carryforward of charitable contribution deductions.

AEP recorded changes in the valuation allowance in the second quarter of 2016 related to the reversal of a $56 million unrealized capital loss where AEP effectively settled a 2011 audit issue with the IRS. AEP also recorded changes in the third quarter of 2016 by reducing the capital loss valuation allowance by $66 million to reflect the impact of the reclassification of certain assets held for sale and the filing of the 2015 federal income tax return. The sale of these assets held for sale are expected to result in a gain, the character of which will allow AEP to recognize the capital loss and allowed AEP to reverse substantially all of the remaining capital loss valuation allowance previously recorded. During the fourth quarter of 2016, AEP reversed $6 million of the valuation allowance associated with charitable contributions that expired at the end of the year. As of December 31, 2016 there was a valuation allowance of $2 million recorded against AEP's deferred tax asset balance related to an unrealized capital loss carryforward.

Valuation allowance activity for the years ended December 31, 2018 and 2017 was immaterial.

Federal and State Income Tax Audit Status

AEP and subsidiaries are no longer subject to U.S. federal examination for years before 2011. The IRS examination of years 2011 through 2013 started in April 2014. AEP and subsidiaries received a Revenue Agents Report in April 2016, completing the 2011 through 2013 audit cycle indicating an agreed upon audit. The 2011 through 2013 audit was submitted to the Congressional Joint Committee on Taxation for approval. The Joint Committee referred the audit back to the IRS exam team for further consideration. To resolve the issue under consideration, AEP and subsidiaries and the IRS exam team agreed to utilize the Fast Track Settlement Program in December 2017. The program was completed in March 2018 and tax years 2014 and 2015 were added to the IRS examination to reflect the impact of the Fast Track changes that were carried forward to 2014 and 2015. In June 2018, AEP settled all outstanding issues under audit for tax years 2011-2015. As a result, the related $72 million unrecognized tax benefit was reversed in the second quarter of 2018. The Joint Committee approved the settlement in November 2018. The settlement did not materially impact the Registrants net income, cash flows or financial condition. The IRS examination of 2016 began in October 2018.

AEP and subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns. AEP and subsidiaries are currently under examination in several state and local jurisdictions. However, it is possible that previously filed tax returns have positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. The Registrants are no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2007.

Net Income Tax Operating Loss Carryforward

As of December 31, 2018, AEP, AEPTCo, I&M, PSO and SWEPCo have state net income tax operating loss carryforwards as indicated in the table below:

Company	State/Municipality	State Net Income Tax Operating Loss Carryforward	Years of Expiration
		(in millions)	
AEP	Arkansas	$ 67.8	2018 - 2023
AEP	Kentucky	130.4	2025 - 2037
AEP	Louisiana	517.3	2030 - 2038
AEP	Oklahoma	644.2	2032 - 2037
AEP	Tennessee	28.6	2025 - 2033
AEP	Virginia	22.8	2030 - 2038
AEP	West Virginia	5.1	2029 - 2037
AEP	Ohio Municipal	226.5	2019 - 2023
AEPTCo	Oklahoma	264.0	2032 - 2037
AEPTCo	Ohio Municipal	43.6	2019 - 2023
I&M	West Virginia	3.8	2032 - 2037
PSO	Oklahoma	348.8	2034 - 2037
SWEPCo	Arkansas	67.1	2021 - 2023
SWEPCo	Louisiana	504.9	2032 - 2037

As of December 31, 2018, AEP and AEPTCo have recorded valuation allowances of $5 million and $1 million, respectively, against certain state and municipal net income tax operating loss carryforwards since future taxable income is not expected to be sufficient to realize the remaining state net income tax operating loss tax benefits before the carryforward expires. Management anticipates future taxable income will be sufficient to realize the remaining state net income tax operating loss tax benefits before the carryforward expires for each state.

Tax Credit Carryforward

Federal and state net income tax operating losses sustained in 2017, 2012, 2011 and 2009 along with lower federal and state taxable income in 2010 resulted in unused federal and state income tax credits. As of December 31, 2018, the Registrants have federal tax credit carryforwards and AEP and PSO have state tax credit carryforwards as indicated in the table below. If these credits are not utilized, federal general business tax credits will expire in the years 2037 through 2038.

Company	Total Federal Tax Credit Carryforward	Federal Tax Credit Carryforward Subject to Expiration	Total State Tax Credit Carryforward	State Tax Credit Carryforward Subject to Expiration
		(in millions)		
AEP	$ 113.7	$ 100.9	$ 34.2	$ —
APCo	0.2	—	—	—
I&M	0.9	—	—	—
PSO	—	—	34.2	—

The Registrants anticipate future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused.

Uncertain Tax Positions

The reconciliations of the beginning and ending amounts of unrecognized tax benefits are as follows:

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Balance as of January 1, 2018	$ 86.6	$ (0.8)	$ —	$ —	$ 3.2	$ 6.9	$ —	$ (0.8)
Increase – Tax Positions Taken During a Prior Period	0.1	—	—	—	—	—	—	—
Decrease – Tax Positions Taken During a Prior Period	—	—	—	—	—	—	—	—
Increase – Tax Positions Taken During the Current Year	—	—	—	—	—	—	—	—
Decrease – Tax Positions Taken During the Current Year	—	—	—	—	—	—	—	—
Decrease – Settlements with Taxing Authorities	(71.0)	—	—	—	—	—	—	—
Decrease – Lapse of the Applicable Statute of Limitations	(1.1)	—	—	—	—	—	—	—
Balance as of December 31, 2018	$ 14.6	$ (0.8)	$ —	$ —	$ 3.2	$ 6.9	$ —	$ (0.8)

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Balance as of January 1, 2017	$ 98.8	$ 6.5	$ —	$ —	$ 3.8	$ 6.9	$ 0.1	$ 1.3
Increase – Tax Positions Taken During a Prior Period	4.5	2.0	—	—	0.2	—	0.1	1.7
Decrease – Tax Positions Taken During a Prior Period	(28.0)	(12.3)	—	—	(0.5)	—	(0.9)	(5.4)
Increase – Tax Positions Taken During the Current Year	3.4	—	—	—	—	—	—	—
Decrease – Tax Positions Taken During the Current Year	—	—	—	—	—	—	—	—
Decrease – Settlements with Taxing Authorities	7.9	3.0	—	—	(0.3)	—	0.7	1.6
Decrease – Lapse of the Applicable Statute of Limitations	—	—	—	—	—	—	—	—
Balance as of December 31, 2017	$ 86.6	$ (0.8)	$ —	$ —	$ 3.2	$ 6.9	$ —	$ (0.8)

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Balance as of January 1, 2016	$ 187.0	$ 27.8	$ —	$ 0.3	$ 2.4	$ 6.9	$ 1.3	$ 9.3
Increase – Tax Positions Taken During a Prior Period	86.0	6.5	—	—	1.8	—	0.1	1.3
Decrease – Tax Positions Taken During a Prior Period	(161.2)	(15.0)	—	(0.3)	(0.4)	—	(1.3)	(9.3)
Increase – Tax Positions Taken During the Current Year	—	—	—	—	—	—	—	—
Decrease – Tax Positions Taken During the Current Year	—	—	—	—	—	—	—	—
Decrease – Settlements with Taxing Authorities	(13.0)	(12.8)	—	—	—	—	—	—
Decrease – Lapse of the Applicable Statute of Limitations	—	—	—	—	—	—	—	—
Balance as of December 31, 2016	$ 98.8	$ 6.5	$ —	$ —	$ 3.8	$ 6.9	$ 0.1	$ 1.3

Management believes that there will be no significant net increase or decrease in unrecognized benefits within 12 months of the reporting date. The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for each Registrant was as follows:

Company	2018	2017	2016
	(in millions)		
AEP	$ 11.6	$ 10.5	$ 15.8
AEP Texas	(0.7)	(0.5)	4.2
AEPTCo	—	—	—
APCo	—	—	—
I&M	2.6	2.1	2.5
OPCo	5.4	4.5	4.4
PSO	—	—	0.1
SWEPCo	(0.6)	(0.5)	0.8

State Tax Legislation

In March 2016, the Texas Comptroller of Public Accounts issued clarifying guidance regarding the treatment of transmission and distribution expenses included in the computation of taxable income for purposes of calculating the Texas income/franchise tax. The guidance clarified which specific transmission and distribution expenses are included in the computation of the cost of goods sold deduction. This guidance resulted in a net favorable adjustment to net income of $21 million, $7 million, $2 million and $9 million in 2016 for AEP, AEP Texas, PSO and SWEPCo, respectively.

In April 2018, the Kentucky legislature enacted House Bill (H.B.) 487. H.B. 487 adopts mandatory unitary combined reporting for state corporate income tax purposes applicable for taxable years beginning on or after January 1, 2019. H.B. 487 also adopts the 80% federal net operating loss (NOL) limitation under Internal Revenue Code Section 172(a) for NOLs generated after January 1, 2018 and the federal unlimited carryforward period for unused NOLs generated after January 1, 2018. In addition, H.B. 366 was also enacted in April 2018, which among other things, replaces the graduated corporate tax rate structure with a flat 5% tax rate for business income and adopts a single-sales factor apportionment formula for apportioning a corporation's business income to Kentucky. In the second quarter of 2018, AEP recorded an $18 million benefit to Income Tax Expense as a result of remeasuring Kentucky deferred taxes under a unitary filing group. The enacted legislation did not materially impact AEPTCo's, I&M's or OPCo's net income.

In June 2018, the United States Supreme Court issued a decision which eliminated a physical presence requirement for the imposition of sales and use tax and instead applied an economic nexus concept. Although this case was specific to sales and use taxes, many states are beginning to consider whether they could also apply this economic nexus concept to income taxes. Management continues to monitor state legislation to determine whether it could create any income tax liability in any states in which AEP currently does not file.

13. LEASES

The disclosures in this note apply to all Registrants unless indicated otherwise.

Leases of property, plant and equipment are for remaining periods up to 17 years and require payments of related property taxes, maintenance and operating costs. Many of the leases have purchase or renewal options. Leases not renewed are often replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Additionally, for regulated operations with capital leases, a capital lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs were as follows:

Year Ended December 31, 2018	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Net Lease Expense on Operating Leases	$ 245.0	$ 13.6	$ 2.7	$ 18.2	$ 89.2	$ 10.7	$ 5.7	$ 6.5
Amortization of Capital Leases	62.4	4.8	0.1	7.0	6.6	3.9	3.2	11.2
Interest on Capital Leases	16.4	1.2	—	3.0	3.3	0.5	0.4	3.2
Total Lease Rental Costs	$ 323.8	$ 19.6	$ 2.8	$ 28.2	$ 99.1	$ 15.1	$ 9.3	$ 20.9

Year Ended December 31, 2017	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Net Lease Expense on Operating Leases	$ 231.3	$ 10.5	$ 1.7	$ 17.5	$ 88.4	$ 8.2	$ 4.4	$ 5.3
Amortization of Capital Leases	66.3	4.0	—	6.9	11.1	4.1	4.0	11.2
Interest on Capital Leases	16.7	0.8	—	3.7	3.2	0.5	0.6	3.6
Total Lease Rental Costs	$ 314.3	$ 15.3	$ 1.7	$ 28.1	$ 102.7	$ 12.8	$ 9.0	$ 20.1

Year Ended December 31, 2016	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Net Lease Expense on Operating Leases	$ 224.9	$ 9.8 (a)	$ 0.9	$ 16.6	$ 90.5	$ 7.1	$ 5.0	$ 6.7
Amortization of Capital Leases	93.7	3.4	—	6.4	35.6	4.2	3.7	13.6
Interest on Capital Leases	18.9	0.6	—	3.5	3.7	0.5	0.6	5.1
Total Lease Rental Costs	$ 337.5	$ 13.8	$ 0.9	$ 26.5	$ 129.8	$ 11.8	$ 9.3	$ 25.4

(a) Amounts include lease expenses related to Desert Sky and Trent that were classified as Other Operation Expense from Discontinued Operations on the statements of income in the amount of $1 million for the year ended December 31, 2016. See Note 7 - Dispositions and Impairments for additional information.

The following tables show the property, plant and equipment under capital leases and related obligations recorded on the Registrants' balance sheets. Unless shown as a separate line on the balance sheets due to materiality, current capital lease obligations are included in Other Current Liabilities and long-term capital lease obligations are included in Deferred Credits and Other Noncurrent Liabilities on the Registrants' balance sheets.

December 31, 2018	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Property, Plant and Equipment Under Capital Leases:								
Generation	$ 131.3	$ —	$ —	$ 38.7	$ 27.0	$ —	$ 2.6	$ 34.3
Other Property, Plant and Equipment	373.9	38.8	0.2	17.3	33.3	20.4	17.6	119.8
Total Property, Plant and Equipment	505.2	38.8	0.2	56.0	60.3	20.4	20.2	154.1
Accumulated Amortization	226.4	10.3	0.1	16.2	21.6	8.3	7.9	99.9
Net Property, Plant and Equipment Under Capital Leases	$ 278.8	$ 28.5	$ 0.1	$ 39.8	$ 38.7	$ 12.1	$ 12.3	$ 54.2
Obligations Under Capital Leases:								
Noncurrent Liability	$ 233.5	$ 24.0	$ —	$ 33.7	$ 33.4	$ 9.2	$ 9.5	$ 50.6
Liability Due Within One Year	55.5	4.5	0.1	6.1	5.3	2.9	2.8	10.2
Total Obligations Under Capital Leases	$ 289.0	$ 28.5	$ 0.1	$ 39.8	$ 38.7	$ 12.1	$ 12.3	$ 60.8

December 31, 2017	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
Property, Plant and Equipment Under Capital Leases:								
Generation	$ 141.7	$ —	$ —	$ 42.5	$ 27.2	$ —	$ 8.9	$ 33.4
Other Property, Plant and Equipment	373.3	32.7	0.2	18.0	34.0	22.8	18.0	122.4
Total Property, Plant and Equipment	515.0	32.7	0.2	60.5	61.2	22.8	26.9	155.8
Accumulated Amortization	229.0	10.0	—	19.0	21.1	10.6	15.3	94.0
Net Property, Plant and Equipment Under Capital Leases	$ 286.0	$ 22.7	$ 0.2	$ 41.5	$ 40.1	$ 12.2	$ 11.6	$ 61.8
Obligations Under Capital Leases:								
Noncurrent Liability	$ 238.8	$ 18.5	$ 0.1	$ 34.9	$ 34.3	$ 7.9	$ 8.3	$ 57.8
Liability Due Within One Year	59.0	4.2	0.1	6.6	5.8	4.3	3.5	11.2
Total Obligations Under Capital Leases	$ 297.8	$ 22.7	$ 0.2	$ 41.5	$ 40.1	$ 12.2	$ 11.8	$ 69.0

Future minimum lease payments consisted of the following as of December 31, 2018:

Capital Leases	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
2019	$ 70.8	$ 5.8	$ 0.1	$ 9.0	$ 8.2	$ 3.3	$ 3.4	$ 13.1
2020	60.2	5.3	—	8.0	7.2	2.7	2.6	11.5
2021	51.7	4.7	—	7.3	6.6	2.3	2.0	10.5
2022	43.8	4.2	—	6.8	6.1	1.7	1.6	9.4
2023	35.5	3.7	—	6.3	5.7	1.2	1.4	8.6
Later Years	90.2	10.1	—	13.3	21.7	2.8	3.3	18.7
Total Future Minimum Lease Payments	352.2	33.8	0.1	50.7	55.5	14.0	14.3	71.8
Less Estimated Interest Element	63.2	5.3	—	10.9	16.8	1.9	2.0	11.0
Estimated Present Value of Future Minimum Lease Payments	$ 289.0	$ 28.5	$ 0.1	$ 39.8	$ 38.7	$ 12.1	$ 12.3	$ 60.8

Noncancelable Operating Leases	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
2019	$ 259.6	$ 15.1	$ 2.3	$ 17.6	$ 92.6	$ 14.5	$ 6.5	$ 7.4
2020	250.1	14.1	1.8	16.5	89.3	13.2	6.0	7.2
2021	232.7	13.2	1.0	13.9	84.8	10.9	5.0	6.7
2022	222.5	12.2	0.5	12.8	83.8	10.0	4.6	6.1
2023	58.3	10.8	0.1	9.9	6.5	8.8	4.1	5.0
Later Years	165.2	28.4	—	20.5	19.5	31.7	10.7	11.7
Total Future Minimum Lease Payments	$ 1,188.4	$ 93.8	$ 5.7	$ 91.2	$ 376.5	$ 89.1	$ 36.9	$ 44.1

Master Lease Agreements (Applies to all Registrants except AEPTCo)

The Registrants lease certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, the Registrants are committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the amount guaranteed. As of December 31, 2018, the maximum potential loss by the Registrants for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term was as follows:

Company	Maximum Potential Loss
	(in millions)
AEP	$ 47.7
AEP Texas	10.8
APCo	8.8
I&M	3.7
OPCo	7.9
PSO	3.8
SWEPCo	4.3

Rockport Lease (Applies to AEP and I&M)

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant, Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it equally to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. AEP, AEGCo and I&M have no ownership interest in the Owner Trustee and do not guarantee its debt. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2018 were as follows:

Future Minimum Lease Payments	AEP (a)	I&M
	(in millions)	
2019	$ 147.8	$ 73.9
2020	147.8	73.9
2021	147.8	73.9
2022	147.2	73.6
Total Future Minimum Lease Payments	$ 590.6	$ 295.3

(a) AEP's future minimum lease payments include equal shares from AEGCo and I&M.

Railcar Lease (Applies to AEP, I&M and SWEPCo)

In 2003, AEP Transportation LLC, a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. In 2008, AEP Transportation LLC assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignments are accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo exercised all renewal options for the maximum lease term. The future minimum lease obligations were $6 million and $7 million for I&M and SWEPCo, respectively, for the remaining railcars as of December 31, 2018. These obligations are included in the future minimum lease payments schedule earlier in this note.

Under the remaining five-year lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which is equal to 77% of the projected fair value of the equipment. I&M and SWEPCo assumed the guarantee under the return-and-sale option. The maximum potential losses related to the guarantee were $5 million and $5 million for I&M and SWEPCo, respectively, as of December 31, 2018, assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, management believes that the fair value would produce a sufficient sales price to avoid any loss.

AEPRO Boat and Barge Leases (Applies to AEP)

In 2015, AEP sold its commercial barge transportation subsidiary, AEPRO, to a nonaffiliated party. Certain boat and barge leases acquired by the nonaffiliated party are subject to an AEP guarantee in favor of the lessor, ensuring future payments under such leases with maturities up to 2027. As of December 31, 2018, the maximum potential amount of future payments required under the guaranteed leases was $44 million. In certain instances, AEP has no recourse against the nonaffiliated party if required to pay a lessor under a guarantee, but AEP would have access to sell the leased assets in order to recover payments made by AEP under the guarantee. As of December 31, 2018, AEP's boat and barge lease guarantee liability was $5 million, of which $1 million was recorded in Other Current Liabilities and $4 million was recorded in Deferred Credits and Other Noncurrent Liabilities on AEP's balance sheet.

In January 2018, S&P Global Inc. downgraded the ratings of the nonaffiliated party and set their outlook to negative. In April 2018, Moody's Investors Service Inc. also downgraded their rating and set their outlook to negative. It is reasonably possible that enforcement of AEP's liability for future payments under these leases could be exercised, which could reduce future net income and cash flows and impact financial condition.

14. FINANCING ACTIVITIES

The disclosures in this note apply to all Registrants, unless indicated otherwise.

Common Stock (Applies to AEP)

The following table is a reconciliation of common stock share activity:

Shares of AEP Common Stock	Issued	Held in Treasury	
Balance, December 31, 2015	511,389,173	20,336,592	
Issued	659,347	—	
Balance, December 31, 2016	512,048,520	20,336,592	
Issued	162,124	—	
Treasury Stock Reissued	—	(131,546)	(a)
Balance, December 31, 2017	512,210,644	20,205,046	
Issued	1,239,392	—	
Treasury Stock Reissued	—	(886)	(a)
Balance, December 31, 2018	513,450,036	20,204,160	

(a) Reissued Treasury Stock used to fulfill share commitments related to AEP's Share-based Compensation. See "Shared-based Compensation Plans" section of Note 15 for additional information.

Long-term Debt

The following table details long-term debt outstanding:

Company	Maturity	Weighted-Average Interest Rate as of December 31, 2018	Interest Rate Ranges as of December 31, 2018	Interest Rate Ranges as of December 31, 2017	Outstanding as of December 31, 2018	Outstanding as of December 31, 2017
AEP					(in millions)	
Senior Unsecured Notes	2018-2048	4.36%	2.15%-8.13%	2.15%-8.13%	$ 18,903.3	$ 16,478.3
Pollution Control Bonds (a)	2018-2038 (b)	3.14%	1.60%-6.30%	1.54%-6.30%	1,643.8	1,621.7
Notes Payable – Nonaffiliated (c)	2019-2032	3.95%	3.20%-6.37%	2.03%-6.37%	204.7	260.8
Securitization Bonds	2018-2028 (d)	3.65%	1.98%-5.31%	1.98%-5.31%	1,111.4	1,416.5
Spent Nuclear Fuel Obligation (e)					273.6	268.6
Other Long-term Debt	2018-2059	3.72%	1.15%-13.718%	1.15%-13.718%	1,209.9	1,127.4
Total Long-term Debt Outstanding					$ 23,346.7	$ 21,173.3
AEP Texas						
Senior Unsecured Notes	2018-2047	4.06%	2.40%-6.76%	2.40%-6.76%	$ 2,398.4	$ 1,932.2
Pollution Control Bonds	2020-2030	4.39%	1.75%-6.30%	1.75%-6.30%	490.9	490.5
Securitization Bonds	2018-2024 (d)	3.95%	1.98%-5.31%	1.98%-5.31%	791.2	1,026.1
Other Long-term Debt	2019-2059	3.94%	3.94%-4.50%	2.75%-4.50%	200.8	200.5
Total Long-term Debt Outstanding					$ 3,881.3	$ 3,649.3
AEPTCo						
Senior Unsecured Notes	2018-2048	3.92%	2.68%-5.52%	2.68%-5.52%	$ 2,823.0	$ 2,550.4
Total Long-term Debt Outstanding					$ 2,823.0	$ 2,550.4
APCo						
Senior Unsecured Notes	2021-2045	5.20%	3.30%-7.00%	3.30%-7.00%	$ 3,047.3	$ 3,045.1
Pollution Control Bonds (a)	2018-2038 (b)	2.64%	1.70%-5.38%	1.625%-5.38%	616.0	512.2
Securitization Bonds	2023-2028 (d)	3.06%	2.008%-3.772%	2.008%-3.772%	272.3	295.9
Other Long-term Debt	2019-2026	3.91%	3.74%-13.718%	2.73%-13.718%	127.0	126.9
Total Long-term Debt Outstanding					$ 4,062.6	$ 3,980.1
I&M						
Senior Unsecured Notes	2019-2048	4.38%	3.20%-6.05%	3.20%-7.00%	$ 2,149.0	$ 1,809.0
Pollution Control Bonds (a)	2018-2025 (b)	2.49%	1.81%-3.05%	1.75%-2.75%	264.5	264.6
Notes Payable – Nonaffiliated (c)	2019-2022	3.30%	3.20%-3.38%	2.03%-2.19%	135.8	188.6
Spent Nuclear Fuel Obligation (e)					273.6	268.6
Other Long-term Debt	2018-2025	3.80%	3.66%-6.00%	2.82%-6.00%	212.5	214.3
Total Long-term Debt Outstanding					$ 3,035.4	$ 2,745.1
OPCo						
Senior Unsecured Notes	2018-2048	5.52%	4.15%-6.60%	5.375%-6.60%	$ 1,635.5	$ 1,591.4
Pollution Control Bonds	2038	5.80%	5.80%	5.80%	32.3	32.3
Securitization Bonds	2019 (d)	2.049%	2.049%	2.049%	47.8	94.5
Other Long-term Debt	2028	1.15%	1.15%	1.15%	1.0	1.1
Total Long-term Debt Outstanding					$ 1,716.6	$ 1,719.3
PSO						
Senior Unsecured Notes	2019-2046	4.80%	3.05%-6.625%	3.05%-6.625%	$ 1,144.9	$ 1,144.1
Pollution Control Bonds	2020	4.45%	4.45%	4.45%	12.6	12.6
Other Long-term Debt	2019-2027	3.70%	3.00%-3.72%	2.584%-3.00%	129.5	129.8
Total Long-term Debt Outstanding					$ 1,287.0	$ 1,286.5
SWEPCo						
Senior Unsecured Notes	2018-2048	4.04%	2.75%-6.20%	2.75%-6.45%	$ 2,427.0	$ 2,110.7
Pollution Control Bonds	2018-2019	1.60%	1.60%	1.60%-4.95%	53.5	135.1
Notes Payable – Nonaffiliated (c)	2024-2032	5.23%	4.58%-6.37%	4.58%-6.37%	68.9	72.1
Other Long-term Debt	2020-2028	4.03%	3.75%-4.68%	2.925%-4.28%	164.0	124.0
Total Long-term Debt Outstanding					$ 2,713.4	$ 2,441.9

(a) For certain series of Pollution Control Bonds, interest rates are subject to periodic adjustment. Certain series may be purchased on demand at periodic interest adjustment dates. Letters of credit from banks and insurance policies support certain series.

(b) Certain Pollution Control Bonds are subject to redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity purposes as Long-term Debt Due Within One Year - Nonaffiliated on the balance sheets.

(c) Notes payable represent outstanding promissory notes issued under term loan agreements and credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.

(d) Dates represent the scheduled final payment dates for the securitization bonds. The legal maturity date is one to two years later. These bonds have been classified for maturity and repayment purposes based on the scheduled final payment date.

(e) Spent Nuclear Fuel Obligation consists of a liability along with accrued interest for disposal of SNF. See “Spent Nuclear Fuel Disposal” section of Note 6 for additional information.

As of December 31, 2018, outstanding long-term debt was payable as follows:

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
2019	$ 1,698.5	$ 501.1	$ 85.0	$ 430.7	$ 155.4	$ 47.9	$ 375.5	$ 59.7
2020	1,508.3	377.7	—	90.3	41.6	0.1	13.2	121.2
2021	1,961.5	66.2	50.0	393.0	256.4	500.1	250.5	6.2
2022	1,668.4	493.0	104.0	230.4	7.0	0.1	0.5	281.2
2023	539.6	195.0	60.0	26.6	252.4	0.1	0.5	6.2
After 2023	16,150.9	2,275.5	2,551.0	2,924.4	2,351.5	1,182.8	652.0	2,262.9
Principal Amount	23,527.2	3,908.5	2,850.0	4,095.4	3,064.3	1,731.1	1,292.2	2,737.4
Unamortized Discount, Net and Debt Issuance Costs	(180.5)	(27.2)	(27.0)	(32.8)	(28.9)	(14.5)	(5.2)	(24.0)
Total Long-term Debt Outstanding	$ 23,346.7	$ 3,881.3	$ 2,823.0	$ 4,062.6	$ 3,035.4	$ 1,716.6	$ 1,287.0	$ 2,713.4

As of December 31, 2018, trustees held, on behalf of AEP, $574 million of their reacquired Pollution Control Bonds. Of this total, $345 million related to OPCo.

Long-term Debt Subsequent Events

In January and February 2019, I&M retired $15 million and $2 million, respectively, of Notes Payable related to DCC Fuel.

In January and February 2019, Transource Energy issued $3 million and $3 million, respectively, of variable rate Other Long-term Debt due in 2020.

In January 2019, AEP Texas retired $104 million of Securitization Bonds.

In January 2019, OPCo retired $23 million of Securitization Bonds.

In January 2019, SWEPCo retired $54 million of 1.60% Pollution Control Bonds due in 2019.

In February 2019, APCo retired $12 million of Securitization Bonds.

Debt Covenants (Applies to AEP and AEPTCo)

Covenants in AEPTCo's note purchase agreements and indenture limit the amount of contractually-defined priority debt (which includes a further sub-limit of $50 million of secured debt) to 10% of consolidated tangible net assets. AEPTCo's contractually-defined priority debt was 0.6% of consolidated tangible net assets as of December 31,2018. The method for calculating the consolidated tangible net assets is contractually-defined in the note purchase agreement.

Dividend Restrictions

Utility Subsidiaries' Restrictions

Parent depends on its utility subsidiaries to pay dividends to shareholders. AEP utility subsidiaries pay dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends.

All of the dividends declared by AEP's utility subsidiaries that provide transmission or local distribution services are subject to a Federal Power Act restriction that prohibits the payment of dividends out of capital accounts without regulatory approval; payment of dividends is allowed out of retained earnings only. However, the Federal Power Act creates a reserve on retained earnings attributable to hydroelectric generation plants. Because of their ownership of such plants, this reserve applies to AGR, APCo and I&M.

Certain AEP subsidiaries have credit agreements that contain covenants that limit their debt to capitalization ratio to 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

The most restrictive dividend limitation for certain AEP subsidiaries is through the Federal Power Act restriction, while for other AEP subsidiaries the most restrictive dividend limitation is through the credit agreements. As of December 31, 2018, the maximum amount of restricted net assets of AEP's subsidiaries that may not be distributed to the Parent in the form of a loan, advance or dividend was $12.4 billion.

The Federal Power Act restriction limits the ability of the AEP subsidiaries owning hydroelectric generation to pay dividends out of retained earnings. Additionally, the credit agreement covenant restrictions can limit the ability of the AEP subsidiaries to pay dividends out of retained earnings. As of December 31, 2018, the amount of any such restrictions were as follows:

	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
Restricted Retained Earnings	$ 1,591.4 (a)	$ 353.7	$ —	$ 17.6	$ 454.1	$ —	$ 152.7	$ 526.4

(a) Includes the restrictions of consolidated and non-consolidated subsidiaries.

Parent Restrictions (Applies to AEP)

The holders of AEP's common stock are entitled to receive the dividends declared by the Board of Directors provided funds are legally available for such dividends. Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries.

Pursuant to the leverage restrictions in credit agreements, AEP must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements. As of December 31, 2018, AEP had $7.7 billion of available retained earnings to pay dividends to common shareholders. AEP paid $1.3 billion, $1.2 billion and $1.1 billion of dividends to common shareholders for the years ended December 31, 2018, 2017 and 2016, respectively.

Lines of Credit and Short-term Debt (Applies to AEP and SWEPCo)

AEP uses its commercial paper program to meet the short-term borrowing needs of its subsidiaries. The program funds a Utility Money Pool, which funds AEP's utility subsidiaries; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and the short-term debt requirements of subsidiaries that are not participating in either money pool for regulatory or operational reasons, as direct borrowers. As of December 31, 2018, AEP had a $4 billion revolving credit facility to support its commercial paper program. The commercial paper program for the year ended 2018, had a weighted-average interest rate of 2.33% and a maximum amount outstanding of $2.3 billion. AEP's outstanding short-term debt was as follows:

		December 31,			
		2018		2017	
Company	**Type of Debt**	**Outstanding Amount**	**Interest Rate (a)**	**Outstanding Amount**	**Interest Rate (a)**
		(in millions)		(in millions)	
AEP	Securitized Debt for Receivables (b)	$ 750.0	2.16%	$ 718.0	1.22%
AEP	Commercial Paper	1,160.0	2.96%	898.6	1.85%
SWEPCo	Notes Payable	—	—%	22.0	2.92%
	Total Short-term Debt	$ 1,910.0		$ 1,638.6	

(a) Weighted-average interest rate.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.

Corporate Borrowing Program – AEP System (Applies to Registrant Subsidiaries)

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and direct borrowing from AEP. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of December 31, 2018 and 2017 are included in Advances to Affiliates and Advances from Affiliates, respectively, on the Registrant Subsidiaries' balance sheets. The Utility Money Pool participants' money pool activity and corresponding authorized borrowing limits are described in the following tables:

Year Ended December 31, 2018:

Company	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Net Loans to (Borrowings from) the Utility Money Pool as of December 31, 2018	Authorized Short-term Borrowing Limit	
			(in millions)				
AEP Texas	$ 390.6	$ 106.9	$ 176.0	$ 47.1	$ (216.0)	$ 500.0	
AEPTCo	371.3	276.4	177.9	58.4	35.8	795.0	(a)
APCo	295.5	23.7	175.3	23.3	(182.6)	600.0	
I&M	322.1	657.8	255.5	110.7	11.6	500.0	
OPCo	270.8	225.0	167.8	189.4	(114.1)	500.0	
PSO	193.7	31.8	104.5	12.9	(105.5)	300.0	
SWEPCo	200.1	533.7	143.2	268.1	81.4	350.0	

Year Ended December 31, 2017:

Company	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Net Loans to (Borrowings from) the Utility Money Pool as of December 31, 2017	Authorized Short-term Borrowing Limit	
			(in millions)				
AEP Texas	$ 296.0	$ 451.7	$ 194.8	$ 264.6	$ 103.5	$ 400.0	
AEPTCo	467.2	268.0	180.5	119.8	109.2	795.0	(a)
APCo	231.5	160.7	144.3	30.0	(162.5)	600.0	
I&M	367.4	12.6	204.9	12.6	(199.2)	500.0	
OPCo	280.6	56.2	137.0	27.9	(87.8)	400.0	
PSO	185.2	—	119.3	—	(149.6)	300.0	
SWEPCo	187.5	178.6	95.5	169.5	(118.7)	350.0	

(a) Amount represents the combined authorized short-term borrowing limit the State Transcos have from FERC or state regulatory commissions.

The activity in the above tables does not include short-term lending activity of certain AEP nonutility subsidiaries. AEP Texas' wholly-owned subsidiary, AEP Texas North Generation Company, LLC and SWEPCo's wholly-owned subsidiary, Mutual Energy SWEPCo, LLC participate in the Nonutility Money Pool. The amounts of outstanding loans to the Nonutility Money Pool as of December 31, 2018 and 2017 are included in Advances to Affiliates on each subsidiaries' balance sheets. The Nonutility Money Pool participants' money pool activity is described in the following tables:

Year Ended December 31, 2018:

Company	Maximum Loans to the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of December 31, 2018
	(in millions)		
AEP Texas	$ 8.4	$ 8.1	$ 8.0
SWEPCo	2.0	2.0	2.0

Year Ended December 31, 2017:

Company	Maximum Loans to the Nonutility Money Pool	Average Loans to the Nonutility Money Pool	Loans to the Nonutility Money Pool as of December 31, 2017
	(in millions)		
AEP Texas	$ 8.6	$ 8.3	$ 8.4
SWEPCo	2.0	2.0	2.0

AEP has a direct financing relationship with AEPTCo to meet its short-term borrowing needs. In January 2017, management removed AEP Texas from the direct financing relationship with AEP to better reflect current business operations. The amounts of outstanding loans to and borrowings from AEP as of December 31, 2018 and 2017 are included in Advances to Affiliates and Advances from Affiliates, respectively, on AEPTCo' balance sheets. AEPTCo's direct financing activities with AEP are described in the following tables:

Year Ended December 31, 2018:

Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings From AEP as of December 31, 2018	Loans to AEP as of December 31, 2018	Authorized Short-term Borrowing Limit	
			(in millions)				
$ 1.2	$ 104.7	$ 1.1	$ 49.8	$ 1.2	$ 16.9	$ 75.0	(a)

Year Ended December 31, 2017:

Maximum Borrowings from AEP	Maximum Loans to AEP	Average Borrowings from AEP	Average Loans to AEP	Borrowings from AEP as of December 31, 2017	Loans to AEP as of December 31, 2017	Authorized Short-term Borrowing Limit	
			(in millions)				
$ 4.1	$ 151.9	$ 1.1	$ 39.3	$ 1.1	$ 22.5	$ 75.0	(a)

(a) Amount represents the combined authorized short-term borrowing limit the State Transcos have from FERC or state regulatory commissions.

The maximum and minimum interest rates for funds either borrowed from or loaned to the Utility Money Pool are summarized in the following table:

	Years Ended December 31,		
	2018	2017	2016
Maximum Interest Rate	2.97%	1.85%	1.02%
Minimum Interest Rate	1.81%	0.92%	0.69%

The average interest rates for funds borrowed from and loaned to the Utility Money Pool are summarized in the following table:

	Average Interest Rate for Funds Borrowed from the Utility Money Pool for the Years Ended December 31,			Average Interest Rate for Funds Loaned to the Utility Money Pool for the Years Ended December 31,		
Company	2018	2017	2016	2018	2017	2016
AEP Texas	2.26%	1.29%	0.88%	2.29%	1.26%	0.72%
AEPTCo	2.27%	1.36%	0.85%	2.10%	1.27%	0.83%
APCo	2.26%	1.28%	0.80%	2.21%	1.29%	0.82%
I&M	2.16%	1.27%	0.80%	2.08%	1.29%	0.80%
OPCo	2.18%	1.37%	0.85%	2.47%	0.98%	0.74%
PSO	2.27%	1.32%	0.96%	1.98%	—%	0.83%
SWEPCo	2.31%	1.28%	0.79%	2.00%	0.98%	0.90%

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Nonutility Money Pool are summarized in the following tables:

Year Ended December 31, 2018:

Company	Maximum Interest Rate for Funds Borrowed from the Nonutility Money Pool	Minimum Interest Rate for Funds Borrowed from the Nonutility Money Pool	Maximum Interest Rate for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rate for Funds Loaned to the Nonutility Money Pool	Average Interest Rate for Funds Borrowed from the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool
AEP Texas	—%	—%	2.97%	1.83%	—%	2.36%
SWEPCo	—%	—%	2.97%	1.83%	—%	2.36%

Year Ended December 31, 2017:

Company	Maximum Interest Rate for Funds Borrowed from the Nonutility Money Pool	Minimum Interest Rate for Funds Borrowed from the Nonutility Money Pool	Maximum Interest Rate for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rate for Funds Loaned to the Nonutility Money Pool	Average Interest Rate for Funds Borrowed from the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool
AEP Texas	—%	—%	1.85%	—%	—%	1.32%
SWEPCo	—%	—%	1.85%	—%	—%	1.32%

Year Ended December 31, 2016:

Company	Maximum Interest Rate for Funds Borrowed from the Nonutility Money Pool	Minimum Interest Rate for Funds Borrowed from the Nonutility Money Pool	Maximum Interest Rate for Funds Loaned to the Nonutility Money Pool	Minimum Interest Rate for Funds Loaned to the Nonutility Money Pool	Average Interest Rate for Funds Borrowed from the Nonutility Money Pool	Average Interest Rate for Funds Loaned to the Nonutility Money Pool
AEP Texas	1.11%	0.97%	1.02%	0.75%	1.00%	0.86%
SWEPCo	—%	—%	1.02%	0.69%	—%	0.82%

Maximum, minimum and average interest rates for funds either borrowed from or loaned to AEP are summarized in the following tables:

Year Ended December 31, 2018:

Company	Maximum Interest Rate for Funds Borrowed from AEP	Minimum Interest Rate for Funds Borrowed from AEP	Maximum Interest Rate for Funds Loaned to AEP	Minimum Interest Rate for Funds Loaned to AEP	Average Interest Rate for Funds Borrowed from AEP	Average Interest Rate for Funds Loaned to AEP
AEP Texas	—%	—%	—%	—%	—%	—%
AEPTCo	2.97%	1.76%	2.97%	1.76%	2.36%	2.36%

Year Ended December 31, 2017:

Company	Maximum Interest Rate for Funds Borrowed from AEP	Minimum Interest Rate for Funds Borrowed from AEP	Maximum Interest Rate for Funds Loaned to AEP	Minimum Interest Rate for Funds Loaned to AEP	Average Interest Rate for Funds Borrowed from AEP	Average Interest Rate for Funds Loaned to AEP
AEP Texas	—%	—%	—%	—%	—%	—%
AEPTCo	1.85%	0.92%	1.85%	0.92%	1.33%	1.36%

Year Ended December 31, 2016:

Company	Maximum Interest Rate for Funds Borrowed from AEP	Minimum Interest Rate for Funds Borrowed from AEP	Maximum Interest Rate for Funds Loaned to AEP	Minimum Interest Rate for Funds Loaned to AEP	Average Interest Rate for Funds Borrowed from AEP	Average Interest Rate for Funds Loaned to AEP
AEP Texas	0.98%	0.69%	1.02%	0.99%	0.83%	1.00%
AEPTCo	1.02%	0.69%	1.02%	0.69%	0.83%	0.87%

Interest expense and interest income related to the Utility Money Pool, Nonutility Money Pool and direct borrowing financing relationship are included in Interest Expense and Interest Income, respectively, on each of the Registrant Subsidiaries' statements of income. The interest expense and interest income related to the corporate borrowing programs were immaterial for the years ended December 31, 2018, 2017 and 2016.

Credit Facilities

See "Letters of Credit" section of Note 6 for additional information.

Securitized Accounts Receivables – AEP Credit (Applies to AEP)

AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the receivables AEP Credit acquires from affiliated utility subsidiaries. These securitized transactions allow AEP Credit to repay its outstanding debt obligations, continue to purchase the operating companies' receivables and accelerate AEP Credit's cash collections.

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and includes a $125 million and a $625 million facility which expire in July 2020 and 2021, respectively.

Accounts receivable information for AEP Credit was as follows:

	Years Ended December 31, 2018	2017	2016
	(dollars in millions)		
Effective Interest Rates on Securitization of Accounts Receivable	2.16%	1.22%	0.70%
Net Uncollectible Accounts Receivable Written Off	$ 27.6	$ 23.4	$ 23.7

	December 31, 2018	2017
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 972.5	$ 925.5
Short-term – Securitized Debt of Receivables	750.0	718.0
Delinquent Securitized Accounts Receivable	50.3	41.1
Bad Debt Reserves Related to Securitization	27.5	28.7
Unbilled Receivables Related to Securitization	281.4	303.2

AEP Credit's delinquent customer accounts receivable represent accounts greater than 30 days past due.

Securitized Accounts Receivables – AEP Credit (Applies to Registrant Subsidiaries, except AEPTCo and AEP Texas)

Under this sale of receivables arrangement, the Registrant Subsidiaries sell, without recourse, certain of their customer accounts receivable and accrued unbilled revenue balances to AEP Credit and are charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for each Registrant Subsidiary's receivables. APCo does not have regulatory authority to sell its West Virginia accounts receivable. The costs of customer accounts receivable sold are reported in Other Operation expense on the Registrant Subsidiaries' statements of income. The Registrant Subsidiaries manage and service their customer accounts receivable, which are sold to AEP Credit. AEP Credit securitizes the eligible receivables for the operating companies and retains the remainder.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreement were:

Company	December 31, 2018	2017
	(in millions)	
APCo	$ 133.3	$ 136.2
I&M	152.9	136.5
OPCo	395.2	367.4
PSO	109.7	115.1
SWEPCo	150.3	138.2

The fees paid to AEP Credit for customer accounts receivable sold were:

Company	Years Ended December 31, 2018	2017	2016
	(in millions)		
APCo	$ 7.0	$ 5.6	$ 6.7
I&M	9.2	6.7	7.1
OPCo	26.3	21.7	28.9
PSO	7.9	7.0	6.2
SWEPCo	8.9	7.2	6.9

The proceeds on the sale of receivables to AEP Credit were:

Company	Years Ended December 31, 2018	2017	2016
	(in millions)		
APCo	$ 1,421.0	$ 1,372.8	$ 1,412.5
I&M	1,843.0	1,612.9	1,596.2
OPCo	2,674.5	2,339.0	2,633.0
PSO	1,484.6	1,337.0	1,269.3
SWEPCo	1,736.1	1,563.4	1,531.7

15. STOCK-BASED COMPENSATION

The disclosures in this note apply to AEP only. The impact of AEP's share-based compensation plans is insignificant to the financial statements of the Registrant Subsidiaries.

Awards under AEP's long-term incentive plan may be granted to employees and directors. The Amended and Restated American Electric Power System Long-Term Incentive Plan (the "Prior Plan"), was replaced prospectively for new grants by the American Electric Power System 2015 Long-Term Incentive Plan (the "2015 LTIP") effective in April 2015. The 2015 LTIP was subsequently amended in September 2016. The 2015 LTIP provides for a maximum of 10 million common shares to be available for grant to eligible employees and directors. As of December 31, 2018, 8,194,046 shares remained available for issuance under the 2015 LTIP. No new awards may be granted under the Prior Plan. The 2015 LTIP awards may be stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance share units, cash-based awards and other stock-based awards. If a share is issued pursuant to a stock option or a stock appreciation right, it will reduce the aggregate amount authorized under the 2015 LTIP by 0.286 of a share. If a share is issued for any other award that settles in AEP stock, it will reduce the aggregate amount authorized under the 2015 LTIP by one share. Cash settled awards do not reduce the aggregate amount authorized under the 2015 LTIP. The following sections provide further information regarding each type of stock-based compensation award granted under these plans.

Performance Units

Performance units granted prior to 2017 are settled in cash rather than AEP common stock and do not reduce the aggregate share authorization. These performance units have a fair value upon vesting equal to the average closing market price of AEP common stock for the last 20 trading days of the performance period. Performance units granted from 2017 on will be settled in AEP common stock and will reduce the aggregate share authorization. In all cases the number of performance units held at the end of the three-year performance period is multiplied by the performance score for such period to determine the actual number of performance units that participants realize. The performance score can range from 0% to 200% and is determined at the end of the performance period based on performance measures, which include both performance and market conditions, established for each grant at the beginning of the performance period by the Human Resources Committee of AEP's Board of Directors (HR Committee).

Certain employees must satisfy stock ownership requirements. If those employees have not met their stock ownership requirements, a portion or all of their performance units are mandatorily deferred as AEP career shares to the extent needed to meet their stock ownership requirement. AEP career shares are a form of non-qualified deferred compensation that has a value equivalent to shares of AEP common stock. AEP career shares are settled in AEP common stock after the participant's termination of employment.

AEP career shares are recorded in Paid-in Capital on the balance sheets. Amounts equivalent to cash dividends on both performance units and AEP career shares accrue as additional units. Management records compensation cost for performance units over an approximately three-year vesting period. The liability for the pre 2017 performance units is recorded in Employee Benefits and Pension Obligations on the balance sheets and is adjusted for changes in value. Performance units settled in shares are recorded as mezzanine equity on the balance sheets and compensation cost is calculated at fair value using two metrics. Half is based on the total shareholder return measure, which is determined based on a third party Monte Carlo valuation. That metric does not change over the three-year vesting period. The other half is based on a three-year cumulative earnings per share metric which is adjusted quarterly for changes in performance relative to a target approved by the HR Committee.

The HR Committee awarded performance units and reinvested dividends on outstanding performance units and AEP career shares for the years ended December 31, 2018, 2017 and 2016 as follows:

Performance Units	Years Ended December 31, 2018	2017	2016
Awarded Units (in thousands) (a)	581.4	590.7	597.4
Weighted Average Unit Fair Value at Grant Date	$ 67.21	$ 69.78	$ 62.77
Vesting Period (in years)	3	3	3

Performance Units and AEP Career Shares (Reinvested Dividends Portion)	Years Ended December 31, 2018	2017	2016
Awarded Units (in thousands) (b)	80.2	74.6	89.2
Weighted Average Fair Value at Grant Date	$ 70.58	$ 72.35	$ 63.83
Vesting Period (in years)	(c)	(c)	(c)

(a) Awarded units in 2018 and 2017 were mezzanine equity awards and awarded units in 2016 were liability awards.
(b) Awarded dividends in 2018 and 2017 were a mix of equity awards and liability awards, and all awarded dividends in 2016 were liability awards.
(c) The vesting period for the reinvested dividends on performance units is equal to the remaining life of the related performance units. Dividends on AEP career shares vest immediately when the dividend is awarded but are not settled in AEP common stock until after the participant's AEP employment ends.

Performance scores and final awards are determined and approved by the HR Committee in accordance with the pre-established performance measures within approximately one month after the end of the performance period. The performance scores for all performance periods were dependent on two equally-weighted performance measures: (a) three-year total shareholder return measured relative to a peer group of similar companies and (b) three-year cumulative earnings per share measured relative to a target approved by the HR Committee.

The certified performance scores and units earned for the three-year periods ended December 31, 2018, 2017 and 2016 were as follows:

Performance Units	Years Ended December 31, 2018	2017	2016
Certified Performance Score	136.7%	164.8%	163.9%
Performance Units Earned	820,780	956,055	1,111,966
Performance Units Mandatorily Deferred as AEP Career Shares	11,248	20,213	9,963
Performance Units Voluntarily Deferred into the Incentive Compensation Deferral Program	56,826	47,177	51,684
Performance Units to be Settled in Cash	752,706	888,665	1,050,319

The settlements for the years ended December 31, 2018, 2017 and 2016 were as follows:

Performance Units and AEP Career Shares	Years Ended December 31, 2018	2017	2016
		(in millions)	
Cash Settlements for Performance Units	$ 66.9	$ 64.9	$ 62.7
Cash Settlements for Career Share Distributions	—	—	9.1
AEP Common Stock Settlements for Career Share Distributions	5.1	0.4	—

A summary of the status of AEP's nonvested Performance Units as of December 31, 2018 and changes during the year ended December 31, 2018 were as follows:

Nonvested Performance Units	Shares/Units	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested as of January 1, 2018	587.5	$ 64.48
Granted	617.3	67.43
Vested	—	—
Forfeited	(33.5)	65.50
Nonvested as of December 31, 2018	1,171.3	66.01

Monte Carlo Valuation

AEP engages a third party for a Monte Carlo valuation to calculate half of the fair value for the performance units awarded during and after 2017. The valuations use a lattice model and the expected volatility assumptions used were the historical volatilities for AEP and the members of their peer group. The Assumptions used in the Monte Carlo valuations for the years ended December 31, 2018 and 2017 were as follows:

	Years Ended December 31,	
Monte Carlo Valuation	2018	2017
Valuation Period (in years) (a)	2.87	2.86
Expected Volatility Minimum	14.77%	15.65%
Expected Volatility Maximum	26.72%	27.19%
Expected Volatility Average	17.90%	19.07%
Dividend Rate (b)	—%	—%
Risk Free Rate	2.34%	1.44%

(a) Period from award date to vesting date.
(b) Equivalent to reinvesting dividends.

Restricted Stock Units

The HR Committee grants restricted stock units (RSUs), which generally vest, subject to the participant's continued employment, over at least three years in approximately equal annual increments. The RSUs accrue dividends as additional RSUs. The additional RSUs granted as dividends vest on the same date as the underlying RSUs. RSUs are converted into shares of AEP common stock upon vesting, except that RSUs granted prior to 2017 that vest to AEP's executive officers are settled in cash. Executive officers are those officers who are subject to the disclosure requirements set forth in Section 16 of the Securities Exchange Act of 1934. For RSUs settled in shares, compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of RSUs granted by the grant date market closing price. For RSUs settled in cash, compensation cost is recorded over the vesting period and adjusted for changes in fair value until vested. The fair value at vesting is determined by multiplying the number of RSUs vested by the 20-day average closing price of AEP common stock. The maximum contractual term of outstanding RSUs is approximately 40 months from the grant date.

The HR Committee awarded RSUs, including additional units awarded as dividends, for the years ended December 31, 2018, 2017 and 2016 as follows:

	Years Ended December 31,		
Restricted Stock Units	2018	2017	2016
Awarded Units (in thousands)	260.0	255.8	242.0
Weighted Average Grant Date Fair Value	$ 67.96	$ 65.26	$ 62.88

The total fair value and total intrinsic value of restricted stock units vested during the years ended December 31, 2018, 2017 and 2016 were as follows:

Restricted Stock Units	Years Ended December 31, 2018	2017	2016
	(in millions)		
Fair Value of Restricted Stock Units Vested	$ 16.6	$ 16.1	$ 16.4
Intrinsic Value of Restricted Stock Units Vested (a)	19.2	20.0	21.0

(a) Intrinsic value is calculated as market price at exercise date.

A summary of the status of AEP's nonvested RSUs as of December 31, 2018 and changes during the year ended December 31, 2018 were as follows:

Nonvested Restricted Stock Units	Shares/Units	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested as of January 1, 2018	529.6	$ 62.13
Granted	260.0	67.96
Vested	(277.5)	59.77
Forfeited	(23.0)	64.84
Nonvested as of December 31, 2018	489.1	66.01

The total aggregate intrinsic value of nonvested RSUs as of December 31, 2018 was $37 million and the weighted average remaining contractual life was 1.65 years.

Other Stock-Based Plans

AEP also has a Stock Unit Accumulation Plan for Non-Employee Directors providing each non-employee director with AEP stock units as a substantial portion of their quarterly compensation for their services as a director. The number of stock units provided is based on the closing price of AEP common stock on the last trading day of the quarter for which the stock units were earned. Amounts equivalent to cash dividends on the stock units accrue as additional AEP stock units. The stock units granted to non-employee directors are fully vested upon grant date. Stock units are settled in cash upon termination of board service or up to 10 years later if the participant so elects. Cash settlements for stock units are calculated based on the average closing price of AEP common stock for the last 20 trading days prior to the distribution date. After five years of service on the Board of Directors, non-employee directors receive contributions to an AEP stock fund awarded under the Stock Unit Accumulation Plan. Such amounts may be exchanged into other market-based investments that are similar to the investment options available to employees that participate in AEP's Incentive Compensation Deferral Plan.

Management records compensation cost for stock units when the units are awarded and adjusts the liability for changes in value based on the current 20-day average closing price of AEP common stock on the valuation date.

For the years ended December 31, 2018, 2017 and 2016, cash settlements for stock unit distributions were immaterial.

The Board of Directors awarded stock units, including units awarded for dividends, for the years ended December 31, 2018, 2017 and 2016 as follows:

Stock Unit Accumulation Plan for Non-Employee Directors	Years Ended December 31, 2018	2017	2016
Awarded Units (in thousands)	11.4	14.8	19.1
Weighted Average Grant Date Fair Value	$ 70.41	$ 70.79	$ 64.96

Share-based Compensation Plans

For share-based payment arrangements the compensation cost, the actual tax benefit from the tax deductions for compensation cost recognized in income and the total compensation cost capitalized for the years ended December 31, 2018, 2017 and 2016 were as follows:

Share-based Compensation Plans	Years Ended December 31, 2018	2017	2016
	(in millions)		
Compensation Cost for Share-based Payment Arrangements (a)	$ 53.2	$ 79.5	$ 66.5
Actual Tax Benefit (b)	7.7	18.9	23.3
Total Compensation Cost Capitalized	19.7	26.4	20.8

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance expenses on the statements of income.

(b) In December 2017, Tax Reform modified Section 162(m) of the Internal Revenue Code. Beginning after 2017, AEP can no longer deduct certain compensation expense in excess of $1 million for certain named executive officers. This will reduce the tax benefit going forward.

As of December 31, 2018, there was $60 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the 2015 LTIP and Prior Plan. Unrecognized compensation cost related to unvested share-based arrangements will change as the fair value of performance units are adjusted each period and as forfeitures for all award types are realized. AEP's unrecognized compensation cost will be recognized over a weighted-average period of 1.4 years.

Under the 2015 LTIP and Prior Plan, AEP is permitted to use authorized but unissued shares, treasury shares, shares acquired in the open market specifically for distribution under these plans, or any combination thereof to fulfill share commitments. AEP's current practice is to use authorized but unissued shares to fulfill share commitments. The number of shares used to fulfill share commitments is generally reduced to offset AEP's tax withholding obligation.

16. RELATED PARTY TRANSACTIONS

The disclosures in this note apply to all Registrant Subsidiaries unless indicated otherwise.

For other related party transactions, also see "AEP System Tax Allocation Agreement" section of Note 12 in addition to "Corporate Borrowing Program – AEP System" and "Securitized Accounts Receivables – AEP Credit" sections of Note 14.

Power Coordination Agreement (PCA) and Bridge Agreement (Applies to all Registrant Subsidiaries except AEP Texas and AEPTCo)

Effective January 1, 2014, the FERC approved the following agreements.

- Under the FERC approved PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. The PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.
- A Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent. The Bridge Agreement is an interim arrangement that, amongst other things, addresses the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo, PSO, SWEPCo and WPCo. Certain power and natural gas risk management activities for APCo, I&M, KPCo and WPCo are allocated based on the four member companies' respective equity positions, while power and natural gas risk management activities for PSO and SWEPCo are allocated based on the Operating Agreement. With the transfer of OPCo's generation assets to AGR in 2014, AEPSC conducts only gasoline, diesel fuel, energy procurement and risk management activities on OPCo's behalf.

System Integration Agreement (SIA) (Applies to APCo, I&M, PSO and SWEPCo)

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity. Margins resulting from trading and marketing activities originating in PJM generally accrue to the benefit of APCo, I&M, KPCo and WPCo, while trading and marketing activities originating in SPP generally accrue to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the equity positions of these companies.

Affiliated Revenues and Purchases

The following tables show the revenues derived from direct sales to affiliates, auction sales to affiliates, net transmission agreement sales and other revenues for the years ended December 31, 2018, 2017 and 2016:

Related Party Revenues	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Year Ended December 31, 2018							
Direct Sales to East Affiliates	$ —	$ —	$ 133.2	$ 0.1	$ —	$ —	$ —
Direct Sales to West Affiliates	—	—	—	—	—	—	—
Auction Sales to OPCo (a)	—	—	5.8	7.1	—	—	—
Direct Sales to AEPEP	103.6	—	—	—	—	—	—
Transmission Agreement and Transmission Coordination Agreement Sales	—	591.4	36.4	11.7	3.9	0.9	26.9
Other Revenues	1.6	7.5	6.0	3.2	17.1	4.5	1.5
Total Affiliated Revenues	$ 105.2	$ 598.9	$ 181.4	$ 22.1	$ 21.0	$ 5.4	$ 28.4

Related Party Revenues	AEP Texas	AEPTCo		APCo	I&M	OPCo	PSO	SWEPCo
					(in millions)			
Year Ended December 31, 2017								
Direct Sales to East Affiliates	$ —	$ —		$ 130.4	$ —	$ —	$ —	$ —
Direct Sales to West Affiliates	—	—		—	3.8	—	—	—
Auction Sales to OPCo (a)	—	—		1.0	—	—	—	—
Direct Sales to AEPEP	63.6	—		—	—	—	—	(0.2)
Transmission Agreement and Transmission Coordination Agreement Sales	—	559.6	(b)	34.1	(4.4)	6.2	—	24.2
Other Revenues	2.1	8.5		6.5	2.4	18.2	4.3	1.9
Total Affiliated Revenues	$ 65.7	$ 568.1		$ 172.0	$ 1.8	$ 24.4	$ 4.3	$ 25.9

Related Party Revenues	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)			
Year Ended December 31, 2016							
Direct Sales to East Affiliates	$ —	$ —	$ 126.0	$ —	$ —	$ —	$ —
Direct Sales to West Affiliates	—	—	—	—	—	—	3.7
Auction Sales to OPCo (a)	—	—	9.2	12.0	—	—	—
Direct Sales to AEPEP	73.9	—	—	—	—	—	(0.2)
Transmission Agreement and Transmission Coordination Agreement Sales	—	366.1	1.3	12.2	(2.0)	(1.7)	19.4
Other Revenues	1.8	—	5.6	2.0	19.3	4.3	1.6
Total Affiliated Revenues	$ 75.7	$ 366.1	$ 142.1	$ 26.2	$ 17.3	$ 2.6	$ 24.5

(a) Refer to the Ohio Auctions section below for further information regarding these amounts.
(b) Reflects the revisions made to AEPTCo's previously issued financial statements. See the "Revisions to Previously Issued Financial Statements" section of Note 1 for additional information.

The following tables show the purchased power expenses incurred for purchases under the Interconnection Agreement and from affiliates for the years ended December 31, 2018, 2017 and 2016. AEP Texas, AEPTCo, APCo and SWEPCo did not purchase any power from affiliates for the years ended December 31, 2018, 2017 and 2016.

Related Party Purchases	I&M	OPCo	PSO
		(in millions)	
Year Ended December 31, 2018			
Auction Purchases from AEPEP (a)	$ —	$ 79.7	$ —
Auction Purchases from AEP Energy (a)	—	41.0	—
Auction Purchases from AEPSC (a)	—	14.6	—
Direct Purchases from AEGCo	237.9	—	—
Total Affiliated Purchases	$ 237.9	$ 135.3	$ —

Related Party Purchases	I&M	OPCo	PSO
		(in millions)	
Year Ended December 31, 2017			
Auction Purchases from AEPEP (a)	$ —	$ 96.5	$ —
Auction Purchases from AEP Energy (a)	—	5.5	—
Auction Purchases from AEPSC (a)	—	6.5	—
Direct Purchases from AEGCo	223.9	—	—
Total Affiliated Purchases	$ 223.9	$ 108.5	$ —

Related Party Purchases	I&M	OPCo	PSO
		(in millions)	
Year Ended December 31, 2016			
Direct Purchases from West Affiliates	$ —	$ —	$ 3.7
Auction Purchases from AEPEP (a)	—	110.1	—
Auction Purchases from AEP Energy (a)	—	7.7	—
Auction Purchases from AEPSC (a)	—	24.1	—
Direct Purchases from AEGCo	228.6	—	—
Total Affiliated Purchases	$ 228.6	$ 141.9	$ 3.7

(a) Refer to the Ohio Auctions section below for further information regarding this amount.

The above summarized related party revenues and expenses are reported in Sales to AEP Affiliates and Purchased Electricity from AEP Affiliates, respectively, on the Registrant Subsidiaries' statements of income. Since the Registrant Subsidiaries are included in AEP's consolidated results, the above summarized related party transactions are eliminated in total in AEP's consolidated revenues and expenses.

Transmission Agreement (TA) and Transmission Coordination Agreement (TCA) (Applies to all Registrant Subsidiaries except AEP Texas)

APCo, I&M, KGPCo, KPCo, OPCo and WPCo (AEP East Companies) are parties to the TA, which defines how transmission costs through PJM OATT are allocated among the AEP East Companies on a 12-month average coincident peak basis.

The following table shows the net charges recorded by APCo, I&M and OPCo for the years ended December 31, 2018, 2017 and 2016 related to the TA:

Company	Years Ended December 31, 2018	2017	2016
		(in millions)	
APCo	$ 128.3	$ 158.2	$ 103.2
I&M	91.4	103.8	53.0
OPCo	210.1	248.6	143.6

The charges shown above are recorded in Other Operation expenses on the statements of income.

PSO, SWEPCo and AEPSC are parties to the TCA in connection with the operation of the transmission assets of the two AEP utility subsidiaries. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with overseeing the coordinated planning of the transmission facilities of the parties to the agreement. This includes the performance of transmission planning studies, the interaction of such companies with independent system operators and other regional bodies interested in transmission planning and compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such a tariff.

Under the TCA, the parties to the agreement delegated to AEPSC the responsibility of monitoring the reliability of their transmission systems and administering the OATT on their behalf. The allocations have been governed by the FERC-approved OATT for the SPP.

The following table shows the net (revenues) expenses allocated among parties to the TCA pursuant to the SPP OATT protocols as described above for the years ended December 31, 2018, 2017 and 2016:

Company	Years Ended December 31, 2018	2017	2016
	(in millions)		
PSO	$ 65.9	$ 56.0	$ 19.6
SWEPCo	10.5	6.6	(19.6)

The net revenues shown above are recorded in Sales to AEP Affiliates on the statements of income and the net expenses are recorded in Other Operation expenses on the statements of income.

AEPTCo is a load serving entity within the PJM and SPP regions providing transmission services to affiliates in accordance with the OATT, TA and TCA. AEPTCo recorded affiliated transmission revenues related to the TA and TCA in Sales to AEP Affiliates on the statements of income. Refer to the Affiliated Revenues and Purchases section above for amounts related to these transactions.

ERCOT Transmission Service Charges (Applies to AEP and AEP Texas)

Pursuant to an order from the PUCT, ETT bills AEP Texas for its ERCOT wholesale transmission services. ETT billed AEP Texas $27 million, $30 million and $29 million for transmission services in 2018, 2017 and 2016, respectively. The billings are recorded in Other Operation expenses on AEP Texas' statements of income.

Oklaunion PPA between AEP Texas and AEPEP (Applies to AEP Texas)

In 2007, AEP Texas entered into a PPA with an affiliate, AEPEP, whereby AEP Texas agrees to sell AEPEP 100% of AEP Texas' capacity and associated energy from its undivided interest (54.69%) in the Oklaunion Power Station. AEPEP pays AEP Texas for the capacity and associated energy delivered to the delivery point, the sum of fuel, operation and maintenance, depreciation, capacity and all taxes other than federal income taxes applicable. A portion of the payment is fixed and is payable regardless of the level of output. There are no penalties if AEP Texas fails to maintain a minimum availability level or exceeds a maximum heat rate level. The PPA was approved by the FERC. AEP Texas recognizes revenues for the fuel, operations and maintenance and all other taxes as-billed. Revenue is recognized for the capacity and depreciation billed to AEPEP, on a straight-line basis over the term of the PPA as these represent the minimum payments due. In September 2018, the co-owners of Oklaunion Power Station voted to close the plant in 2020. Effective October 2018, AEP Texas increased depreciation expense to ensure the plant balances are fully depreciated as of September 2020 and recovered through the PPA billings to AEPEP. Under the early termination provisions of the PPA, AEPEP expects to pay AEP Texas the full Property, Plant and Equipment balance through depreciation payments over the remaining period of operation of the plant, which is currently estimated to be September 2020.

AEP Texas recorded revenue of $104 million, $64 million and $74 million from AEPEP for the years ended December 31, 2018, 2017 and 2016, respectively. These amounts are included in Sales to AEP Affiliates on AEP Texas' statements of income.

Joint License Agreement (Applies to AEPTCo, I&M, KPCo, OPCo and PSO)

AEPTCo entered into a 50-year joint license agreement with I&M, KPCo, OPCo and PSO, respectively, allowing either party to occupy the granting party's facilities or real property. After the expiration of the agreement, the term shall automatically renew for successive one-year terms unless either party provides notice. The joint license billing provides compensation to the granting party for the cost of carrying assets, including depreciation expense, property taxes, interest expense, return on equity and income taxes. For the years ended December 31, 2018, 2017 and 2016, AEPTCo recorded the following costs in Other Operation expense related to these agreements:

Billing Company	Years Ended December 31, 2018	2017	2016
	(in millions)		
I&M	$ 2.2	$ 1.4	$ 0.8
KPCo	0.2	0.2	0.1
OPCo	2.9	2.4	2.3
PSO	0.3	0.3	0.2

I&M, KPCo, OPCo and PSO recorded income related to these agreements in Sales to AEP Affiliates on the statements of income.

Ohio Auctions (Applies to APCo, I&M and OPCo)

In connection with OPCo's June 2012 - May 2015 ESP, the PUCO ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning in June 2015. AEP Energy, AEPEP, APCo, KPCo, I&M and WPCo participate in the auction process and have been awarded tranches of OPCo's SSO load. Refer to the Affiliated Revenues and Purchases section above for amounts related to these transactions.

Unit Power Agreements (UPA) (Applies to I&M)

UPA between AEGCo and I&M

A UPA between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. Subsequently, I&M assigns 30% of the power to KPCo. See the "UPA between AEGCo and KPCo" section below. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

UPA between AEGCo and KPCo

Pursuant to an assignment between I&M and KPCo and a UPA between AEGCo and KPCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo pays to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo UPA ends in December 2022.

Cook Coal Terminal (Applies to I&M, PSO and SWEPCo)

Cook Coal Terminal, which is owned by AEGCo, performs coal transloading and storage services at cost for I&M. The coal transloading costs were $12 million, $10 million and $13 million in 2018, 2017 and 2016, respectively. I&M recorded the cost of transloading services in Fuel on the balance sheets.

Cook Coal Terminal also performs railcar maintenance services at cost for I&M, PSO and SWEPCo. The railcar maintenance costs in 2018, 2017 and 2016 were as follows:

Company	Years Ended December 31, 2018	2017	2016
		(in millions)	
I&M	$ 1.5	$ 1.3	$ 1.7
PSO	0.7	0.5	0.6
SWEPCo	3.4	3.5	3.3

I&M, PSO and SWEPCo recorded the cost of the railcar maintenance services in Fuel on the balance sheets.

I&M Barging, Urea Transloading and Other Services (Applies to APCo and I&M)

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NO_x emissions at certain generation plants in the AEP System. I&M recorded revenues from barging, transloading and other services in Other Revenues – Affiliated on the statements of income. The affiliated companies recorded these costs paid to I&M as fuel expenses or other operation expenses. The amounts of affiliated expenses were:

Company	Years Ended December 31, 2018	2017	2016
		(in millions)	
AEGCo	$ 19.9	$ 15.3	$ 14.8
AGR	—	0.1	0.3
APCo	35.1	37.2	36.9
KPCo	4.2	5.0	5.3
WPCo	4.2	5.0	4.8

Central Machine Shop (Applies to APCo, I&M, PSO and SWEPCo)

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers the cost of performing these services on the balance sheet and then transfers the cost to the affiliate for reimbursement. The AEP subsidiaries recorded these billings as capital or maintenance expenses depending on the nature of the services received. These billings are recoverable from customers. The following table provides the amounts billed by APCo to the following affiliates:

Company	Years Ended December 31, 2018	2017	2016
		(in millions)	
AGR	$ 1.6	$ 1.2	$ 2.0
I&M	2.4	2.7	2.9
KPCo	1.7	1.8	1.5
PSO	0.5	1.1	0.5
SWEPCo	0.7	0.8	0.9

Sales and Purchases of Property

Certain AEP subsidiaries had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions. The following tables show the sales and purchases, recorded at net book value, for the years ended December 31, 2018, 2017 and 2016:

Sales

	Years Ended December 31,		
Company	**2018**	**2017**	**2016**
		(in millions)	
AEP Texas	$ 0.3	$ 0.2	$ 0.3
APCo	5.4	3.5	4.5
I&M	8.2	5.0	5.2
OPCo	10.7	2.9	1.9
PSO	1.0	1.5	7.5
SWEPCo	0.8	0.5	1.0

Purchases

	Years Ended December 31,		
Company	**2018**	**2017**	**2016**
		(in millions)	
AEP Texas	$ 0.1	$ 0.4	$ 0.7
AEPTCo	18.5	9.1	6.5
APCo	0.6	0.9	1.5
I&M	2.0	3.5	2.7
OPCo	2.8	1.6	1.7
PSO	1.3	0.2	3.2
SWEPCo	0.8	0.4	6.5

The amounts above are recorded in Property, Plant and Equipment on the balance sheets.

Intercompany Billings

The Registrant Subsidiaries and other AEP subsidiaries perform certain utility services for each other when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable basis of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital.

17. VARIABLE INTEREST ENTITIES

The disclosures in this note apply to all Registrants unless indicated otherwise.

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a variable interest in a VIE. A VIE is a legal entity that possesses any of the following conditions: the entity's equity at risk is not sufficient to permit the legal entity to finance its activities without additional subordinated financial support, equity owners are unable to direct the activities that most significantly impact the legal entity's economic performance (or they possess disproportionate voting rights in relation to the economic interest in the legal entity), or the equity owners lack the obligation to absorb the legal entity's expected losses or the right to receive the legal entity's expected residual returns. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether AEP is the primary beneficiary of a VIE, management considers whether AEP has the power to direct the most significant activities of the VIE and is obligated to absorb losses or receive the expected residual returns that are significant to the VIE. Management believes that significant assumptions and judgments were applied consistently.

AEP is the primary beneficiary of Sabine, DCC Fuel, Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, AEP Credit, a protected cell of EIS, Transource Energy and Desert Sky and Trent. In addition, AEP has not provided material financial or other support to any of these entities that was not previously contractually required. AEP holds a significant variable interest in DHLC, OVEC and Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series).

Consolidated Variable Interests Entities (Applies to all Registrants except AEPTCo and PSO)

Sabine

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the years ended December 31, 2018, 2017 and 2016 were $152 million, $137 million and $162 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on SWEPCo's balance sheets.

DCC Fuel

I&M has nuclear fuel lease agreements with DCC Fuel, which was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each DCC Fuel entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Each is a separate legal entity from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the leases for the years ended December 31, 2018, 2017 and 2016 were $113 million, $136 million and $101 million, respectively. The leases were recorded as capital leases on I&M's balance sheets as title to the nuclear fuel transfers to I&M at the end of the respective lease terms, which do not exceed 54 months. Based on I&M's control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital leases are eliminated upon consolidation. See the tables below for the classification of DCC Fuel's assets and liabilities on I&M's balance sheets.

Transition Funding

Transition Funding was formed for the sole purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation. Management has concluded that AEP Texas is the primary beneficiary of Transition Funding because AEP Texas has the power to direct the most significant activities of the VIE and AEP Texas' equity interest could potentially be significant. Therefore, AEP Texas is required to consolidate Transition Funding. The securitized bonds totaled $791 million and $1 billion as of December 31, 2018 and 2017, respectively, and are included in Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the balance sheets. Transition Funding has securitized transition assets of $637 million and $870 million as of December 31, 2018 and 2017, respectively, which are presented separately on the face of the balance sheets. The securitized transition assets represent the right to impose and collect Texas true-up costs from customers receiving electric transmission or distribution service from AEP Texas under recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized transition assets. The bondholders have no recourse to AEP Texas or any other AEP entity. AEP Texas acts as the servicer for Transition Funding's securitized transition assets and remits all related amounts collected from customers to Transition Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Transition Funding's assets and liabilities on the balance sheets.

Ohio Phase-in-Recovery Funding

Ohio Phase-in-Recovery Funding was formed for the sole purpose of issuing and servicing securitization bonds related to phase-in recovery property. Management has concluded that OPCo is the primary beneficiary of Ohio Phase-in-Recovery Funding because OPCo has the power to direct the most significant activities of the VIE and OPCo's equity interest could potentially be significant. Therefore, OPCo is required to consolidate Ohio Phase-in-Recovery Funding. The securitized bonds totaled $48 million and $95 million as of December 31, 2018 and 2017, respectively, and are included in Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the balance sheets. Ohio Phase-in-Recovery Funding has securitized assets of $13 million and $38 million as of December 31, 2018 and 2017, respectively, which are presented separately on the face of the balance sheets. The phase-in recovery property represents the right to impose and collect Ohio deferred distribution charges from customers receiving electric transmission and distribution service from OPCo under a recovery mechanism approved by the PUCO. In August 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to OPCo or any other AEP entity. OPCo acts as the servicer for Ohio Phase-in-Recovery Funding's securitized assets and remits all related amounts collected from customers to Ohio Phase-in-Recovery Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Ohio Phase-in-Recovery Funding's assets and liabilities on OPCo's balance sheets.

Appalachian Consumer Rate Relief Funding

Appalachian Consumer Rate Relief Funding was formed for the sole purpose of issuing and servicing securitization bonds related to APCo's under-recovered ENEC deferral balance. Management has concluded that APCo is the primary beneficiary of Appalachian Consumer Rate Relief Funding because APCo has the power to direct the most significant activities of the VIE and APCo's equity interest could potentially be significant. Therefore, APCo is required to consolidate Appalachian Consumer Rate Relief Funding. The securitized bonds totaled $272 million and $296 million as of December 31, 2018 and 2017, respectively, and are included in Long-term Debt Due Within One Year - Nonaffiliated and Long-term Debt - Nonaffiliated on the balance sheets. Appalachian Consumer Rate Relief Funding has securitized assets of $259 million and $282 million as of December 31, 2018 and 2017, respectively, which are presented separately on the face of the balance sheets. The phase-in recovery property represents the right to impose and collect West Virginia deferred generation charges from customers receiving electric transmission, distribution and generation service from APCo under a recovery mechanism approved by the WVPSC. In November 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to APCo or any other AEP entity. APCo acts as the servicer for Appalachian Consumer Rate Relief Funding's securitized assets and remits all related amounts collected from customers to Appalachian Consumer Rate Relief Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Appalachian Consumer Rate Relief Funding's assets and liabilities on APCo's balance sheets.

AEP Credit

AEP Credit is a wholly-owned subsidiary of Parent. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP provides a minimum of 5% equity and up to 20% of AEP Credit's short-term borrowing needs in excess of third-party financings. Any third-party financing of AEP Credit only has recourse to the receivables securitized for such financing. Based on AEP's control of AEP Credit, management concluded that AEP is the primary beneficiary and is required to consolidate AEP Credit. See the tables below for the classification of AEP Credit's assets and liabilities on the balance sheets. See "Securitized Accounts Receivables - AEP Credit" section of Note 14.

EIS

AEP's subsidiaries participate in one protected cell of EIS for approximately seven lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows certain third-parties access to this insurance. AEP's subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on AEP's control and the structure of the protected cell of EIS, management concluded that AEP is the primary beneficiary of the protected cell and is required to consolidate the protected cell of EIS. The insurance premium expense to the protected cell for the years ended December 31, 2018, 2017 and 2016 was $34 million, $29 million and $28 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on the balance sheets. The amount reported as equity is the protected cell's policy holders' surplus.

Transource Energy

Transource Energy was formed for the purpose of investing in utilities which develop, acquire, construct, own and operate transmission facilities in accordance with FERC-approved rates. AEP has equity and voting ownership of 86.5% with the other owner having 13.5% interest. Management has concluded that Transource Energy is a VIE and that AEP is the primary beneficiary because AEP has the power to direct the most significant activities of the entity and AEP's equity interest could potentially be significant. Therefore, AEP is required to consolidate Transource Energy. Transource Energy's activities consist of the development, construction and operation of FERC-regulated transmission assets in Missouri, West Virginia, Pennsylvania and Maryland. Transource Energy has a credit facility agreement where borrowings are loaned through intercompany lending agreements to its subsidiaries. The creditor to the agreement has no recourse to the general credit of AEP. Transource Energy's credit facility agreement contains certain covenants and require it to maintain a percentage of debt-to-total capitalization at a level that does not exceed 67.5%. For the years ended December 31, 2018, 2017 and 2016, AEP provided capital contributions to Transource Energy of $4 million, $5 million and $45 million, respectively. See the tables below for the classification of Transource Energy's assets and liabilities on the balance sheets.

Desert Sky Wind Farm LLC and Trent Wind Farm LLC

Desert Sky Wind Farm LLC and Trent Wind Farm LLC (collectively "the LLCs") were established for the purpose of repowering, owning and operating wind-powered electric energy generation facilities in Texas. In January 2018, AEP admitted a nonaffiliate as a member of the LLCs to own and repower Desert Sky and Trent. The nonaffiliate contributed full turbine sets to each project in exchange for a 20.1% interest in the LLCs. The nonaffiliates' contribution of $84 million was recorded as Net Property, Plant and Equipment on the balance sheets, which was the fair value as of the contribution date determined based on key input assumptions of the original cost of the full turbine sets and the discounted cash flow benefit associated with the production tax credits available from repowering Desert Sky and Trent based on their expected net capacity, capacity factor and the operational availability. AEP owns 79.9% of the LLCs. As a result, management has concluded that the LLCs are VIEs and that AEP is the primary beneficiary based on its power to direct the activities that most significantly impact their economic performance. Also in January 2018, the LLCs entered into a forward PPA for the sale of power to AEPEP related to deliveries of electricity beginning January 1, 2021 for a 12 year period. Prior to the effective date of the PPA, the LLCs will sell power at market rates into ERCOT. AEP and the nonaffiliate will share tax attributes including production tax credits and cash distributions from the operation of the LLCs generally consistent with the ownership percentages. See the table below for the classification of the LLCs' assets and liabilities on the balance sheets.

AEP has a call right, which if exercised, would require the nonaffiliate to sell its noncontrolling interest in the LLCs to AEP. The call exercise period is for ninety days, beginning July 2020 for Trent Wind Farm LLC and August 2020 for Desert Sky Wind Farm LLC. The nonaffiliates' interest in the LLCs is presented as Redeemable Noncontrolling Interest on the balance sheets. The nonaffiliate holds redemption rights, which if exercised, would require AEP to purchase the nonaffiliates' noncontrolling interest in the LLCs. The redemption right exercise period is for ninety days, beginning July 2021 for Trent Wind Farm LLC and August 2021 for Desert Sky Wind Farm LLC. The exercise price for both the call and redemption right are determined using a discounted cash flow model with agreed input assumptions as well as potential updates to certain assumptions reasonably expected based on the actual results of the LLCs. As of December 31, 2018, AEP recorded $69 million of Redeemable Noncontrolling Interest in Mezzanine Equity on the balance sheets.

The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2018

	Registrant Subsidiaries				
	SWEPCo Sabine	I&M DCC Fuel	AEP Texas Transition Funding	OPCo Ohio Phase-in-Recovery Funding	APCo Appalachian Consumer Rate Relief Funding
	(in millions)				
ASSETS					
Current Assets	$ 70.0	$ 77.6	$ 192.8	$ 29.5	$ 24.8
Net Property, Plant and Equipment	106.9	122.3	—	—	—
Other Noncurrent Assets	98.5	58.4	683.5 (a)	24.2 (b)	261.8 (c)
Total Assets	$ 275.4	$ 258.3	$ 876.3	$ 53.7	$ 286.6
LIABILITIES AND EQUITY					
Current Liabilities	$ 31.1	$ 77.1	$ 271.9	$ 48.5	$ 28.0
Noncurrent Liabilities	244.0	181.2	586.1	3.9	256.7
Equity	0.3	—	18.3	1.3	1.9
Total Liabilities and Equity	$ 275.4	$ 258.3	$ 876.3	$ 53.7	$ 286.6

(a) Includes an intercompany item eliminated in consolidation of $47 million.
(b) Includes an intercompany item eliminated in consolidation of $11 million.
(c) Includes an intercompany item eliminated in consolidation of $3 million.

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2018

	Other Consolidated VIEs			
	AEP Credit	Protected Cell of EIS	Transource Energy	Desert Sky and Trent
	(in millions)			
ASSETS				
Current Assets	$ 974.2	$ 177.8	$ 25.7	$ 6.8
Net Property, Plant and Equipment	—	—	380.3	348.5
Other Noncurrent Assets	6.3	0.1	1.9	—
Total Assets	$ 980.5	$ 177.9	$ 407.9	$ 355.3
LIABILITIES AND EQUITY				
Current Liabilities	$ 923.5	$ 38.6	$ 19.9	$ 8.7
Noncurrent Liabilities	0.8	85.3	160.3	6.2
Equity	56.2	54.0	227.7	340.4
Total Liabilities and Equity	$ 980.5	$ 177.9	$ 407.9	$ 355.3

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2017

	Registrant Subsidiaries				
	SWEPCo Sabine	**I&M DCC Fuel**	**AEP Texas Transition Funding**	**OPCo Ohio Phase-in-Recovery Funding**	**APCo Appalachian Consumer Rate Relief Funding**
	(in millions)				
ASSETS					
Current Assets	$ 56.3	$ 102.5	$ 191.7	$ 28.7	$ 22.3
Net Property, Plant and Equipment	113.2	179.9	—	—	—
Other Noncurrent Assets	90.2	86.3	923.5 (a)	71.0 (b)	285.6 (c)
Total Assets	$ 259.7	$ 368.7	$ 1,115.2	$ 99.7	$ 307.9
LIABILITIES AND EQUITY					
Current Liabilities	$ 49.1	$ 96.5	$ 260.9	$ 47.9	$ 27.6
Noncurrent Liabilities	211.0	272.2	836.1	50.5	278.4
Equity	(0.4)	—	18.2	1.3	1.9
Total Liabilities and Equity	$ 259.7	$ 368.7	$ 1,115.2	$ 99.7	$ 307.9

(a) Includes an intercompany item eliminated in consolidation of $54 million.
(b) Includes an intercompany item eliminated in consolidation of $33 million.
(c) Includes an intercompany item eliminated in consolidation of $3 million.

American Electric Power Company, Inc. and Subsidiary Companies
Variable Interest Entities
December 31, 2017

	Other Consolidated VIEs		
	AEP Credit	**Protected Cell of EIS**	**Transource Energy**
	(in millions)		
ASSETS			
Current Assets	$ 926.3	$ 178.7	$ 17.4
Net Property, Plant and Equipment	—	—	323.9
Other Noncurrent Assets	6.4	—	3.1
Total Assets	$ 932.7	$ 178.7	$ 344.4
LIABILITIES AND EQUITY			
Current Liabilities	$ 872.0	$ 36.4	$ 12.4
Noncurrent Liabilities	0.7	95.2	132.0
Equity	60.0	47.1	200.0
Total Liabilities and Equity	$ 932.7	$ 178.7	$ 344.4

Non-Consolidated Significant Variable Interests

DHLC

DHLC is a mining operator which sells 50% of the lignite produced to SWEPCo and 50% to CLECO. The operations of DHLC are governed by the lignite mining agreement among SWEPCo, CLECO and DHLC. SWEPCo and CLECO share the executive board seats and voting rights equally. In accordance with the lignite mining agreement, each entity is responsible for 50% of DHLC's obligations, including debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee. SWEPCo's total billings from DHLC for the years ended December 31, 2018, 2017 and 2016 were $58 million, $61 million and $65 million, respectively. SWEPCo is not required to consolidate DHLC as it is not the primary beneficiary, although SWEPCo holds a significant variable interest in DHLC. SWEPCo's equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on SWEPCo's balance sheets.

SWEPCo's investment in DHLC was:

	December 31,			
	2018		2017	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from SWEPCo	$ 7.6	$ 7.6	$ 7.6	$ 7.6
Retained Earnings	14.5	14.5	11.8	11.8
SWEPCo's Share of Obligations	—	167.6	—	144.3
Total Investment in DHLC	$ 22.1	$ 189.7	$ 19.4	$ 163.7

OVEC

AEP and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2018, AEP's ownership in OVEC was 43.47%. Parent owns 39.17% and OPCo owns 4.3%. APCo, I&M and OPCo are members to an intercompany power agreement. The Registrants' power participation ratios are 15.69% for APCo, 7.85% for I&M and 19.93% for OPCo. Participants of this agreement are entitled to receive and obligated to pay for all OVEC generating capacity, approximately 2,400 MWs, in proportion to their respective power participation ratios. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs, including outstanding indebtedness, and provide a return on capital. The intercompany power agreement ends in June 2040.

AEP and other nonaffiliated owners authorized environmental investments related to their ownership interests. OVEC financed capital expenditures in connection with the engineering and construction of FGD projects and the associated waste disposal landfills at its two generation plants. These environmental projects were funded through debt issuances. As of December 31, 2018 and 2017, OVEC's outstanding indebtedness was approximately $1.4 billion and $1.4 billion, respectively. Although they are not an obligor or guarantor, the Registrants' are responsible for their respective ratio of OVEC's outstanding debt through the intercompany power agreement. Principal and interest payments related to OVEC's outstanding indebtedness are disclosed in accordance with the accounting guidance for "Commitments." See the "Commitments" section of Note 6 for additional information.

AEP is not required to consolidate OVEC as it is not the primary beneficiary, although AEP and its subsidiary holds a significant variable interest in OVEC. Power to control decision making that significantly impacts the economic performance of OVEC is shared amongst the owners through their representation on the Board of Directors and Operating Committee of OVEC.

AEP's investment in OVEC was:

	December 31,			
	2018		2017	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from AEP	$ 4.4	$ 4.4	$ 4.4	$ 4.4
AEP's Ratio of OVEC Debt (a)	—	604.1	—	626.3
Total Investment in OVEC	$ 4.4	$ 608.5	$ 4.4	$ 630.7

(a) Based on the Registrants' power participation ratios APCo, I&M and OPCo's share of OVEC debt was $218 million, $109 million and $277 million as of December 31, 2018 and $226 million, $113 million and $287 million as of December 31, 2017, respectively.

Power purchased by the Registrant Subsidiaries from OVEC is included in Purchased Electricity for Resale on the statements of income and is shown in the table below:

	Years Ended December 31,		
Company	2018	2017	2016
	(in millions)		
APCo	$ 100.4	$ 101.0	$ 88.0
I&M	50.2	50.5	44.0
OPCo	127.5	128.2	111.7

Potomac-Appalachian Transmission Highline, LLC (PATH)

AEP and FirstEnergy Corp. (FirstEnergy) have a joint venture in PATH. PATH is a series limited liability company and was created to construct, through its operating companies, a high-voltage transmission line project in the PJM region. PATH consists of the "West Virginia Series (PATH-WV)," owned equally by subsidiaries of FirstEnergy and AEP, and the "Allegheny Series" which is 100% owned by a subsidiary of FirstEnergy. Provisions exist within the PATH-WV agreement that make it a VIE. AEP has no interest or control in the "Allegheny Series." AEP is not required to consolidate PATH-WV as AEP is not the primary beneficiary, although AEP holds a significant variable interest in PATH-WV. AEP's equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on the balance sheets. AEP and FirstEnergy share the returns and losses equally in PATH-WV. AEP's subsidiaries and FirstEnergy's subsidiaries provide services to the PATH companies through service agreements. The entities recover costs through regulated rates.

In August 2012, the PJM board cancelled the PATH Project, the transmission project that PATH was intended to develop and removed it from the 2012 Regional Transmission Expansion Plan. In September 2012, the PATH Project companies submitted an application to the FERC requesting authority to recover prudently-incurred costs associated with the PATH Project. In November 2012, the FERC issued an order accepting the PATH Project's abandonment cost recovery application, subject to settlement procedures and hearing. The parties to the case were unable to reach a settlement agreement and in March 2014, settlement judge procedures were terminated. Hearings at the FERC were held in March and April 2015. In April 2015, PATH filed a stipulation agreement with the FERC that agreed to a 50% debt and 50% equity capital structure and a 4.7% cost of long-term debt for the entire amortization period. In September 2015, the ALJ issued an advisory Initial Decision. Additional briefing was submitted during the fourth quarter of 2015. In January 2017, the FERC issued its order on Initial Decision, adopting in part and rejecting in part the ALJ's recommendations. The FERC order included (a) a finding that the PATH Project's abandonment costs were prudently incurred, (b) a finding that the disposition of certain assets was prudent, (c) guidance regarding the future disposition of assets, (d) a reduction of PATH WV's authorized ROE to 8.11% prospectively only after the date of the order, (e) an adjustment of the amortization period to end December 2017, and (f) a credit for certain amounts that were deemed to be not includable in PATH-WV's formula rates.

In February 2017, the PATH Companies filed a request for rehearing of two adverse rulings in the January 2017 FERC order. The request seeks the FERC to reverse its reduction of the PATH Companies 10.4% ROE for the period after January 19, 2017 and to allow the recovery of certain education and outreach costs disallowed by the order. In February 2017, the Edison Electric Institute ("EEI") also filed a request for rehearing recommending reversal of the January 2017 FERC ordered ROE reduction and cost disallowance. The requests for rehearing by the PATH Companies and EEI are currently pending before the FERC. The requests for rehearing do not impact the recovery of costs by the PATH Companies under their formula rates or the timing of the compliance filing required by the order, which was filed in March 2017, and updated in May 2017 and August 2017. As a result of the January 2017 FERC order, PATH-WV is required to refund certain amounts that have been collected under its formula rate in its 2018 Projected Transmission Revenue Requirement. PATH-WV refunded $11.4 million in 2018, including carrying charges, related to the January 2017 order in its 2018 Projected Transmission Revenue Requirement.

In January 2019, FERC issued an order on the PATH Companies' formula rate compliance filing requesting additional information regarding certain additional costs that may be required to be refunded.

AEP's investment in PATH-WV was:

	December 31,			
	2018		2017	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from Parent	$ 18.8	$ 18.8	$ 18.8	$ 18.8
Retained Earnings	(1.4)	(1.4)	(2.0)	(2.0)
Total Investment in PATH-WV	$ 17.4	$ 17.4	$ 16.8	$ 16.8

AEP's investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on the balance sheets. If AEP cannot ultimately recover the investment related to PATH-WV, it could reduce future net income and cash flows and impact financial condition.

AEPSC

AEPSC provides certain managerial and professional services to AEP's subsidiaries. Parent is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside of the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP.

Total AEPSC billings to the Registrant Subsidiaries were as follows:

	Years Ended December 31,		
Company	2018	2017	2016
	(in millions)		
AEP Texas	$ 184.3	$ 152.6	$ 142.3
AEPTCo	220.4	188.9	131.1
APCo	295.6	268.8	244.2
I&M	173.5	176.0	147.7
OPCo	214.9	195.7	181.1
PSO	121.5	114.7	111.0
SWEPCo	164.4	150.7	147.0

The carrying amount and classification of variable interest in AEPSC's accounts payable were as follows:

	December 31,							
	2018				2017			
Company	**As Reported on the Balance Sheet**		**Maximum Exposure**		**As Reported on the Balance Sheet**		**Maximum Exposure**	
	(in millions)							
AEP Texas	$	22.3	$	22.3	$	24.2	$	24.2
AEPTCo		24.6		24.6		25.1		25.1
APCo		32.2		32.2		37.0		37.0
I&M		23.8		23.8		26.8		26.8
OPCo		23.9		23.9		27.4		27.4
PSO		13.2		13.2		18.7		18.7
SWEPCo		18.4		18.4		20.8		20.8

AEGCo

AEGCo, a wholly-owned subsidiary of Parent, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1 and leases a 50% interest in Rockport Plant, Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. I&M is considered to have a significant interest in AEGCo due to these transactions. I&M is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. In the event AEGCo would require financing or other support outside the billings to I&M and KPCo, this financing would be provided by AEP. Total billings to I&M from AEGCo for the years ended December 31, 2018, 2017 and 2016 were $238 million, $224 million and $229 million, respectively. The carrying amount of I&M's liabilities associated with AEGCo as of December 31, 2018 and 2017 was $20 million and $23 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability. See "Rockport Lease" section of Note 13 for additional information.

18. PROPERTY, PLANT AND EQUIPMENT

The disclosures in this note apply to all Registrants unless indicated otherwise.

Property, Plant and Equipment is shown functionally on the face of the Registrants' balance sheets. The following tables include the Registrants' total plant balances as of December 31, 2018 and 2017:

December 31, 2018	AEP		AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo	
					(in millions)					
Regulated Property, Plant and Equipment										
Generation	$ 20,989.1	(a)	$ —	$ —	$ 6,509.6	$ 4,887.2	$ —	$ 1,577.0	$ 4,672.6	(a)
Transmission	21,500.5		3,683.6	6,515.8	3,317.7	1,576.8	2,544.3	892.3	1,866.9	
Distribution	21,192.8		4,043.2	—	3,989.4	2,249.7	4,942.3	2,572.8	2,178.6	
Other	3,770.8		724.6	172.6	457.4	543.1	563.7	298.1	485.2	
CWIP	4,352.6	(a)	836.0	1,578.3	490.2	465.3	432.1	94.0	194.7	(a)
Less: Accumulated Depreciation	17,743.1		1,431.2	271.9	4,118.9	3,139.4	2,217.7	1,472.1	2,633.5	
Total Regulated Property, Plant and Equipment - Net	54,062.7		7,856.2	7,994.8	10,645.4	6,582.7	6,264.7	3,962.1	6,764.5	
Nonregulated Property, Plant and Equipment - Net	1,036.4		135.6	1.4	22.9	28.5	10.2	4.6	107.3	
Total Property, Plant and Equipment - Net	$ 55,099.1		$ 7,991.8	$ 7,996.2	$ 10,668.3	$ 6,611.2	$ 6,274.9	$ 3,966.7	$ 6,871.8	

December 31, 2017	AEP		AEP Texas	AEPTCo (b)	APCo	I&M	OPCo	PSO	SWEPCo	
					(in millions)					
Regulated Property, Plant and Equipment										
Generation	$ 20,406.5	(a)	$ —	$ —	$ 6,446.9	$ 4,445.9	$ —	$ 1,577.2	$ 4,624.9	(a)
Transmission	18,942.3		3,053.6	5,319.7	3,019.9	1,504.0	2,419.2	858.8	1,679.8	
Distribution	19,865.9		3,718.6	—	3,763.8	2,069.3	4,626.4	2,445.1	2,095.8	
Other	3,224.8		457.6	125.4	399.5	552.3	485.5	282.0	416.8	
CWIP	3,972.6	(a)	834.4	1,324.0	483.0	460.2	410.1	111.3	220.7	(a)
Less: Accumulated Depreciation	16,906.7		1,399.4	152.6	3,891.1	3,011.7	2,183.9	1,393.6	2,520.5	
Total Regulated Property, Plant and Equipment - Net	49,505.4		6,664.8	6,616.5	10,222.0	6,020.0	5,757.3	3,880.8	6,517.5	
Nonregulated Property, Plant and Equipment - Net	756.1		160.3	1.4	23.1	30.4	9.5	5.4	114.5	
Total Property, Plant and Equipment - Net	$ 50,261.5		$ 6,825.1	$ 6,617.9	$ 10,245.1	$ 6,050.4	$ 5,766.8	$ 3,886.2	$ 6,632.0	

(a) AEP and SWEPCo's regulated generation and regulated CWIP include amounts related to SWEPCo's Arkansas jurisdictional share of the Turk Plant.
(b) The amounts presented reflect the revisions made to AEPTCo's previously issued financial statements. See the "Revisions to Previously Issued Financial Statements" section of Note 1 for additional information.

Depreciation, Depletion and Amortization

The Registrants provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following tables provide total regulated annual composite depreciation rates and depreciable lives for the Registrants:

AEP

Functional Class of Property	2018 Annual Composite Depreciation Rate Ranges	2018 Depreciable Life Ranges (in years)	2017 Annual Composite Depreciation Rate Ranges	2017 Depreciable Life Ranges (in years)	2016 Annual Composite Depreciation Rate Ranges	2016 Depreciable Life Ranges (in years)
Generation	2.4% - 4.0%	20 - 132	2.3% - 3.7%	20 - 132	2.1% - 4.0%	35 - 132
Transmission	1.6% - 2.7%	15 - 81	1.6% - 2.7%	15 - 100	1.5% - 2.7%	15 - 100
Distribution	2.7% - 3.6%	7 - 78	2.7% - 3.7%	5 - 156	2.6% - 3.7%	7 - 156
Other	2.3% - 9.8%	5 - 75	2.3% - 9.2%	5 - 84	3.1% - 8.6%	5 - 84

AEP Texas

Functional Class of Property	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)
Transmission	1.7%	45 - 81	1.7%	45 - 81	1.8%	45 - 81
Distribution	3.6%	7 - 70	3.6%	7 - 70	3.3%	7 - 70
Other	6.0%	5 - 50	8.7%	5 - 50	8.3%	5 - 50

AEPTCo

Functional Class of Property	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)
Transmission	1.9%	20 - 75	1.7%	20 - 100	1.6%	20 - 100

APCo

Functional Class of Property	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)
Generation	3.1%	35 - 112	3.1%	35 - 112	3.1%	35 - 121
Transmission	1.6%	15 - 68	1.6%	15 - 68	1.5%	15 - 68
Distribution	3.6%	10 - 57	3.7%	10 - 57	3.7%	10 - 57
Other	7.4%	5 - 55	6.5%	5 - 55	6.0%	5 - 55

I&M

Functional Class of Property	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)
Generation	3.4%	20 - 132	2.4%	20 - 132	2.4%	59 - 132
Transmission	1.8%	50 - 73	1.7%	50 - 75	1.7%	50 - 75
Distribution	3.1%	9 - 75	2.7%	10 - 70	2.8%	10 - 70
Other	8.9%	5 - 50	8.4%	5 - 45	8.6%	5 - 45

OPCo

2018	2017	2016

Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges (in years)			Annual Composite Depreciation Rate	Depreciable Life Ranges (in years)			Annual Composite Depreciation Rate	Depreciable Life Ranges (in years)		
Transmission	2.3%	39	-	60	2.3%	39	-	60	2.3%	39	-	60
Distribution	3.0%	14	-	65	2.8%	5	-	57	2.8%	7	-	57
Other	6.3%	5	-	50	6.2%	5	-	50	5.9%	5	-	50

PSO

Functional Class of Property	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)
Generation	2.9%	35 - 75	2.4%	35 - 85	2.4%	35 - 85
Transmission	2.3%	45 - 75	2.2%	45 - 100	2.2%	45 - 100
Distribution	2.9%	15 - 78	2.7%	27 - 156	2.7%	27 - 156
Other	6.3%	5 - 64	7.4%	5 - 84	6.4%	5 - 84

SWEPCo

Functional Class of Property	2018 Annual Composite Depreciation Rate	2018 Depreciable Life Ranges (in years)	2017 Annual Composite Depreciation Rate	2017 Depreciable Life Ranges (in years)	2016 Annual Composite Depreciation Rate	2016 Depreciable Life Ranges (in years)
Generation	2.4%	40 - 70	2.3%	40 - 70	2.1%	40 - 70
Transmission	2.2%	50 - 73	2.3%	50 - 73	2.2%	50 - 70
Distribution	2.7%	25 - 70	2.7%	25 - 70	2.6%	25 - 65
Other	8.0%	5 - 55	7.2%	5 - 55	6.8%	5 - 51

The following table includes the nonregulated annual composite depreciation rate ranges and nonregulated depreciable life ranges for AEP and AEP Texas. Depreciation rate ranges and depreciable life ranges are not meaningful for nonregulated property of AEPTCo, APCo, I&M, OPCo, PSO and SWEPCo for 2018, 2017 and 2016.

Functional Class of Property	2018 Annual Composite Depreciation Rate Ranges	2018 Depreciable Life Ranges (in years)	2017 Annual Composite Depreciation Rate Ranges	2017 Depreciable Life Ranges (in years)	2016 Annual Composite Depreciation Rate Ranges	2016 Depreciable Life Ranges (in years)
Generation	3.4% - 22.3%	15 - 59	2.4% - 5.1%	15 - 66	2.8% - 17.2%	40 - 66
Transmission	2.4%	40	0.2%	40	2.3%	43 - 55
Distribution	2.3%	40	2.3%	40	1.3%	40 - 50
Other	16.3%	5 - 50 (a)	12.1%	5 - 50 (a)	9.1%	5 - 50 (a)

(a) SWEPCo's nonregulated property, plant and equipment is depreciated using the straight-line method over a range of 3 to 20 years.

SWEPCo provides for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. SWEPCo uses either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. SWEPCo includes these costs in fuel expense.

For regulated operations, the composite depreciation rate generally includes a component for non-ARO removal costs, which is credited to Accumulated Depreciation and Amortization on the balance sheets. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred.

Asset Retirement Obligations (Applies to all Registrants except AEPTCo)

The Registrants record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, closure and monitoring of underground carbon storage facilities at Mountaineer Plant, wind farms and certain coal mining facilities. I&M records ARO for the decommissioning of the Cook Plant. The Registrants have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since the Registrants plan to use their facilities indefinitely. The retirement obligation would only be recognized if and when the Registrants abandon or cease the use of specific easements, which is not expected.

As of December 31, 2018 and 2017, I&M's ARO liability for nuclear decommissioning of the Cook Plant was $1.66 billion and $1.30 billion, respectively. These liabilities are reflected in Asset Retirement Obligations on I&M's balance sheets. As of December 31, 2018 and 2017, the fair value of I&M's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $2.16 billion and $2.22 billion, respectively. These assets are included in Spent Nuclear Fuel and Decommissioning Trusts on I&M's balance sheets.

The following is a reconciliation of the 2018 and 2017 aggregate carrying amounts of ARO by Registrant:

Company	ARO as of December 31, 2017	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates (a)	ARO as of December 31, 2018
	(in millions)					
AEP (b)(c)(d)(e)	$ 2,005.7	$ 93.7	$ 0.8	$ (87.0)	$ 342.3 (f)	$ 2,355.5
AEP Texas (b)(e)	26.7	1.2	—	(0.1)	0.1	27.9
APCo (b)(e)	125.0	6.6	—	(17.3)	1.8	116.1
I&M (b)(c)(e)	1,321.8	58.7	—	(0.2)	301.0 (f)	1,681.3
OPCo (e)	1.7	0.1	—	—	—	1.8
PSO (b)(e)	54.0	3.2	—	(0.4)	(9.9)	46.9
SWEPCo (b)(d)(e)	169.2	9.1	0.2	(11.7)	40.0	206.8

Company	ARO as of December 31, 2016	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates (a)	ARO as of December 31, 2017
	(in millions)					
AEP (b)(c)(d)(e)	$ 1,934.9	$ 90.9	$ 2.4	$ (104.5)	$ 82.0	$ 2,005.7
AEP Texas (b)(e)	25.5	1.2	—	(0.1)	0.1	26.7
APCo (b)(e)	127.1	7.0	—	(21.7)	12.6	125.0
I&M (b)(c)(e)	1,258.1	55.9	—	(0.1)	7.9	1,321.8
OPCo (e)	1.7	0.1	—	(0.1)	—	1.7
PSO (b)(e)	53.4	3.1	—	(0.5)	(2.0)	54.0
SWEPCo (b)(d)(e)	156.5	8.3	—	(0.3)	4.7	169.2

(a) Primarily related to ash ponds, landfills and mine reclamation, generally due to changes in estimated closure area, volumes and/or unit costs.
(b) Includes ARO related to ash disposal facilities.
(c) Includes ARO related to nuclear decommissioning costs for the Cook Plant of $1.66 billion and $1.30 billion as of December 31, 2018 and 2017, respectively.
(d) Includes ARO related to Sabine and DHLC.
(e) Includes ARO related to asbestos removal.
(f) Revision for Cook Plant related to a new third-party study, which impacted the ARO liability for changes of estimated cash flows and application of a new discount rate.

Allowance for Funds Used During Construction and Interest Capitalization

The Registrants' amounts of Allowance for Equity Funds Used During Construction are summarized in the following table:

Company	Years Ended December 31, 2018	2017	2016
	(in millions)		
AEP	$ 132.5	$ 93.7	$ 113.2
AEP Texas	20.0	6.8	9.2
AEPTCo	70.6	49.0 (a)	52.3
APCo	13.2	9.2	11.7
I&M	11.9	11.1	15.3
OPCo	9.8	6.4	6.0
PSO	0.4	0.5	6.2
SWEPCo	6.0	2.4	11.0

(a) The amount presented reflects the revisions made to AEPTCo's previously issued financial statements. See the "Revisions to Previously Issued Financial Statements" section of Note 1 for additional information.

The Registrants' amounts of allowance for borrowed funds used during construction, including capitalized interest, are summarized in the following table:

Company	Years Ended December 31, 2018	2017	2016
	(in millions)		
AEP	$ 73.6	$ 48.6	$ 51.7
AEP Texas	18.4	6.8	5.9
AEPTCo	26.1	20.2	15.6
APCo	8.4	5.3	6.3
I&M	7.4	6.7	7.2
OPCo	5.8	3.8	3.3
PSO	0.9	1.1	3.4
SWEPCo	4.8	2.1	6.9

Jointly-owned Electric Facilities (Applies to AEP, AEP Texas, I&M, PSO and SWEPCo)

The Registrants have electric facilities that are jointly-owned with affiliated and non-affiliated companies. Using its own financing, each participating company is obligated to pay its share of the costs of these jointly-owned facilities in the same proportion as its ownership interest. Each Registrant's proportionate share of the operating costs associated with these facilities is included in its statements of income and the investments and accumulated depreciation are reflected in its balance sheets under Property, Plant and Equipment as follows:

			Registrant's Share as of December 31, 2018		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
			(in millions)		
AEP					
Conesville Generating Station, Unit 4 (a)(i)(j)	Coal	83.5%	$ 16.4	$ 0.2	$ 2.4
Dolet Hills Power Station, Unit 1 (g)	Lignite	40.2%	336.2	5.1	209.6
Flint Creek Generating Station, Unit 1 (h)	Coal	50.0%	375.1	1.6	88.9
Pirkey Generating Station, Unit 1 (h)	Lignite	85.9%	591.3	16.6	418.0
Oklaunion Power Station (f)	Coal	70.3%	106.4	—	67.8
Turk Generating Plant (h)(k)	Coal	73.3%	1,590.5	1.1	197.5
Total			$ 3,015.9	$ 24.6	$ 984.2
AEP Texas					
Oklaunion Power Station (f)	Coal	54.7%	$ 352.1	$ 0.2	$ 218.6
I&M					
Rockport Generating Plant (c)(d)(e)	Coal	50.0%	$ 1,108.7	$ 50.2	$ 514.1
PSO					
Oklaunion Power Station (f)	Coal	15.6%	$ 106.4	$ —	$ 67.8
SWEPCo					
Dolet Hills Power Station, Unit 1 (g)	Lignite	40.2%	$ 336.2	$ 5.1	$ 209.6
Flint Creek Generating Station, Unit 1 (h)	Coal	50.0%	375.1	1.6	88.9
Pirkey Generating Station, Unit 1 (h)	Lignite	85.9%	591.3	16.6	418.0
Turk Generating Plant (h)(k)	Coal	73.3%	1,590.5	1.1	197.5
Total			$ 2,893.1	$ 24.4	$ 914.0

			Registrant's Share as of December 31, 2017		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
AEP					
Conesville Generating Station, Unit 4 (a)(i)(j)	Coal	83.5%	$ 2.1	$ 4.2	$ 0.1
Dolet Hills Power Station, Unit 1 (g)	Lignite	40.2%	343.1	5.3	214.2
Flint Creek Generating Station, Unit 1 (h)	Coal	50.0%	364.8	8.9	81.6
Pirkey Generating Station, Unit 1 (h)	Lignite	85.9%	589.8	7.8	406.3
Oklaunion Power Station (f)	Coal	70.3%	456.4	1.9	254.6
Turk Generating Plant (h)(k)	Coal	73.3%	1,580.4	3.2	166.6
Transmission (l)	NA	(b)	62.7	0.3	46.1
Total			$ 3,399.3	$ 31.6	$ 1,169.5
AEP Texas					
Oklaunion Power Station (f)	Coal	54.7%	$ 350.7	$ 1.3	$ 194.1
I&M					
Rockport Generating Plant (c)(d)(e)	Coal	50.0%	$ 1,093.9	$ 28.2	$ 562.6
PSO					
Oklaunion Power Station (f)	Coal	15.6%	$ 105.7	$ 0.6	$ 60.5
SWEPCo					
Dolet Hills Power Station, Unit 1 (g)	Lignite	40.2%	$ 343.1	$ 5.3	$ 214.2
Flint Creek Generating Station, Unit 1 (h)	Coal	50.0%	364.8	8.9	81.6
Pirkey Generating Station, Unit 1 (h)	Lignite	85.9%	589.8	7.8	406.3
Turk Generating Plant (h)(k)	Coal	73.3%	1,580.4	3.2	166.6
Total			$ 2,878.1	$ 25.2	$ 868.7

(a) Operated by AGR.
(b) Varying percentages of ownership.
(c) Operated by I&M.
(d) Amounts include I&M's 50% ownership of both Unit 1 and capital additions for Unit 2. Unit 2 is subject to an operating lease with a non-affiliated company. See the "Rockport Lease" section of Note 13.
(e) AEGCo owns 50% of Unit 1 with I&M and 50% of capital additions for Unit 2.
(f) Operated by PSO, which owns 15.6%. Also jointly-owned (54.7%) by AEP Texas and various non-affiliated companies. See the "Impairments" section of Note 7.
(g) Operated by CLECO, a non-affiliated company.
(h) Operated by SWEPCo.
(i) Conesville Generating Station, Unit 4 was impaired as of September 30, 2016. See the "Impairments" section of Note 7.
(j) In accordance with the Asset Purchase Agreement between AGR and Dynegy Corporation dated February 2017, AGR acquired Dynegy Corporation's 40% ownership interest in Conesville Generating Station, Unit 4. Subsequent to this transaction, AGR's ownership percentage in Conesville Generating Station, Unit 4 is 83.5%.
(k) In December 2017, SWEPCo recorded a $15 million pretax impairment related to the Louisiana jurisdictional share of Turk Plant. Amount reflects the impact of the impairment. See the "Impairments" section of Note 7.
(l) In accordance with the 2017 CCD Transmission Asset Exchange Agreement between OPCo, Dayton Power & Light Company and Duke Energy Ohio, Inc., the parties agreed to an exchange and transfer of jointly owned transmission assets in order to eliminate the joint ownership of these assets. The asset exchange closed on June 30, 2018, ending the joint ownership of these transmission assets.
NA Not applicable.

19. GOODWILL

The disclosure in this note applies to AEP only.

The changes in AEP's carrying amount of goodwill for the years ended December 31, 2018 and 2017 by operating segment are as follows:

	Corporate and Other	Generation & Marketing	AEP Consolidated
		(in millions)	
Balance as of December 31, 2016	$ 37.1	$ 15.4	$ 52.5
Impairment Losses	—	—	—
Balance as of December 31, 2017	37.1	15.4	52.5
Impairment Losses	—	—	—
Balance as of December 31, 2018	$ 37.1	$ 15.4	$ 52.5

In the fourth quarters of 2018 and 2017, annual impairment tests were performed. The fair values of the reporting units with goodwill were estimated using cash flow projections and other market value indicators. There were no goodwill impairment losses. AEP does not have any accumulated impairment on existing goodwill.

20. REVENUE FROM CONTRACTS WITH CUSTOMERS

The disclosures in this note apply to all Registrants, unless indicated otherwise.

Disaggregated Revenues from Contracts with Customers

The table below represents AEP's reportable segment revenues from contracts with customers, net of respective provisions for refund, by type of revenue:

	Year Ended December 31, 2018						
	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	Generation & Marketing	Corporate and Other	Reconciling Adjustments	AEP Consolidated
	(in millions)						
Retail Revenues:							
Residential Revenues	$ 3,751.8	$ 2,189.2	$ —	$ —	$ —	$ —	$ 5,941.0
Commercial Revenues	2,206.4	1,273.4	—	—	—	—	3,479.8
Industrial Revenues	2,190.2	494.5	—	—	—	—	2,684.7
Other Retail Revenues	183.1	39.2	—	—	—	—	222.3
Total Retail Revenues	8,331.5	3,996.3	—	—	—	—	12,327.8
Wholesale and Competitive Retail Revenues:							
Generation Revenues (a)	899.8	—	—	544.4	—	(226.0)	1,218.2
Transmission Revenues (b)	282.2	372.1	849.3	—	—	(737.1)	766.5
Marketing, Competitive Retail and Renewable Revenues	—	—	—	1,353.0	—	—	1,353.0
Total Wholesale and Competitive Retail Revenues	1,182.0	372.1	849.3	1,897.4	—	(963.1)	3,337.7
Other Revenues from Contracts with Customers (c)	158.4	204.6	15.2	20.6	86.2	(32.0)	453.0
Total Revenues from Contracts with Customers	9,671.9	4,573.0	864.5	1,918.0	86.2	(995.1)	16,118.5
Other Revenues:							
Alternative Revenues (c)	(15.9)	(22.2)	(60.4)	—	—	52.7	(45.8)
Other Revenues (c)	(10.5)	102.3	—	22.3	8.9	—	123.0
Total Other Revenues	(26.4)	80.1	(60.4)	22.3	8.9	52.7	77.2
Total Revenues	$ 9,645.5	$ 4,653.1	$ 804.1	$ 1,940.3	$ 95.1	$ (942.4)	$ 16,195.7

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for Generation & Marketing was $121 million. The remaining affiliated amounts were immaterial.

(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEP Transmission Holdco was $643 million. The remaining affiliated amounts were immaterial.

(c) Amounts include affiliated and nonaffiliated revenues.

The table below represents revenues from contracts with customers, net of respective provisions for refund, by type of revenue for the Registrant Subsidiaries:

	Year Ended December 31, 2018						
	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)						
Retail Revenues:							
Residential Revenues	$ 578.9	$ —	$ 1,342.6	$ 730.0	$ 1,611.5	$ 659.0	$ 641.5
Commercial Revenues	436.2	—	582.4	490.3	835.7	404.4	491.9
Industrial Revenues	110.0	—	602.4	560.3	385.2	294.1	325.8
Other Retail Revenues	25.9	—	77.4	7.2	12.9	83.3	8.6
Total Retail Revenues	1,151.0	—	2,604.8	1,787.8	2,845.3	1,440.8	1,467.8
Wholesale Revenues:							
Generation Revenues (a)	—	—	250.4	470.5	—	36.3	216.8
Transmission Revenues (b)	313.4	816.9	82.7	23.1	58.5	40.2	108.4
Total Wholesale Revenues	313.4	816.9	333.1	493.6	58.5	76.5	325.2
Other Revenues from Contracts with Customers (c)	28.6	15.1	55.3	99.6	176.1	19.1	24.0
Total Revenues from Contracts with Customers	1,493.0	832.0	2,993.2	2,381.0	3,079.9	1,536.4	1,817.0
Other Revenues:							
Alternative Revenues (d)	(1.3)	(55.9)	(23.8)	(2.1)	(20.8)	10.9	4.9
Other Revenues (d)	103.6	—	(1.9)	(8.2)	4.3	—	—
Total Other Revenues	102.3	(55.9)	(25.7)	(10.3)	(16.5)	10.9	4.9
Total Revenues	$ 1,595.3	$ 776.1	$ 2,967.5	$ 2,370.7	$ 3,063.4	$ 1,547.3	$ 1,821.9

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $134 million primarily relating to the PPA with KGPCo. The remaining affiliated amounts were immaterial.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for AEPTCo was $646 million. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for I&M was $70 million primarily relating to the barging, urea transloading and other transportation services. The remaining affiliated amounts were immaterial.
(d) Amounts include affiliated and nonaffiliated revenues.

Performance Obligations

AEP has performance obligations as part of its normal course of business. A performance obligation is a promise to transfer a distinct good or service, or a series of distinct goods or services that are substantially the same and have the same pattern of transfer to a customer. The invoice practical expedient within the accounting guidance for "Revenue from Contracts with Customers" allows for the recognition of revenue from performance obligations in the amount of consideration to which there is a right to invoice the customer and when the amount for which there is a right to invoice corresponds directly to the value transferred to the customer.

The purpose of the invoice practical expedient is to depict an entity's measure of progress toward completion of the performance obligation within a contract and can only be applied to performance obligations that are satisfied over time and when the invoice is representative of services provided to date. AEP subsidiaries elected to apply the invoice practical expedient to recognize revenue for performance obligations satisfied over time as the invoices from the respective revenue streams are representative of services or goods provided to date to the customer. Performance obligations for AEP's subsidiaries are summarized as follows:

Retail Revenues

AEP's subsidiaries within the Vertically Integrated Utilities and Transmission and Distribution Utilities segments have performance obligations to generate, transmit and distribute electricity for sale to rate-regulated retail customers. The performance obligation to deliver electricity is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Revenues are variable as they are subject to the customer's usage requirements.

Rate-regulated retail customers typically have the right to discontinue receiving service at will, therefore these contracts between AEP's subsidiaries and their customers for rate-regulated services are generally limited to the services requested and received to date for such arrangements. Retail customers are generally billed on a monthly basis, and payment is typically due within 15 to 20 days after the issuance of the invoice. Payments from Retail Electric Providers are due to AEP Texas within 35 days.

Wholesale Revenues - Generation

AEP's subsidiaries within the Vertically Integrated Utilities and Generation & Marketing segments have performance obligations to sell electricity to wholesale customers from generation assets in PJM, SPP and ERCOT. The performance obligation to deliver electricity from generation assets is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Wholesale generation revenues are variable as they are subject to the customer's usage requirements.

AEP's subsidiaries within the Vertically Integrated Utilities and Generation & Marketing segments also have performance obligations to stand ready in order to promote grid reliability. Stand ready services are sold into PJM's RPM capacity market. RPM entails a base auction and at least three incremental auctions for a specific PJM delivery year, with the incremental auctions spanning three years. The performance obligation to stand ready is satisfied over time and the consideration for which is variable until the occurrence of the final incremental auction, at which point the performance obligation becomes fixed.

Payments from the RTO for stand ready services are typically received within one week from the issuance of the invoice, which is typically issued weekly. Gross margin resulting from generation sales within the Vertically Integrated Utilities segment are primarily subject to margin sharing agreements with customers and vary by state, where the revenues are reflected gross in the disaggregated revenues tables above.

APCo has a performance obligation to supply wholesale electricity to KGPCo through a purchased power agreement. The FERC regulates the cost-based wholesale power transactions between APCo and KGPCo. The purchased power agreement includes a component for the recovery of transmission costs under the FERC OATT. The transmission cost component of purchased power is cost-based and regulated by the Tennessee Regulatory Authority. APCo's performance obligation under the purchased power agreement is satisfied over time as KGPCo simultaneously receives and consumes the wholesale electricity. APCo's revenues from the purchased power agreement are presented within the Generation Revenues line in the disaggregated revenues tables above.

Wholesale Revenues - Transmission

AEP's subsidiaries within the Vertically Integrated Utilities, Transmission and Distribution Utilities and AEP Transmission Holdco segments have performance obligations to transmit electricity to wholesale customers through assets owned and operated by AEP subsidiaries. The performance obligation to provide transmission services in PJM, SPP and ERCOT encompass a time frame greater than a year, where the performance obligation within each RTO is partially fixed for a period of one year or less. Payments from the RTO for transmission services are typically received within one week from the issuance of the invoice, which is issued monthly for SPP and ERCOT and weekly for PJM.

AEP subsidiaries within the PJM and SPP regions collect revenues through transmission formula rates. The FERC-approved rates establish the annual transmission revenue requirement (ATRR) and transmission service rates for transmission owners. The formula rates establish rates for a one year period and also include a true-up calculation for

the prior year's billings, allowing for over/under-recovery of the transmission owner's ATRR. The annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations," and are therefore presented as such in the disaggregated revenues tables above. AEP subsidiaries within the ERCOT region collect revenues through a combination of base rates and interim Transmission Costs of Services filings that are approved by the PUCT.

APCo, I&M, KGPCo, KPCo, OPCo and WPCo (AEP East Companies) are parties to the Transmission Agreement (TA), which defines how transmission costs are allocated among the AEP East Companies on a 12-month average coincident peak basis. PSO, SWEPCo and AEPSC are parties to the Transmission Coordination Agreement (TCA) by and among PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two AEP utility subsidiaries. AEPTCo is a load serving entity within the PJM and SPP regions providing transmission services to affiliates in accordance with the OATT, TA and TCA. Affiliate revenues as a result of the respective TA and the TCA are reflected as Transmission Revenues in the disaggregated revenues tables above.

Marketing, Competitive Retail and Renewable Revenues

AEP's subsidiaries within the Generation & Marketing segment have performance obligations to deliver electricity to competitive retail and wholesale customers. Performance obligations for marketing, competitive retail and renewable offtake sales are satisfied over time as the customer simultaneously receives and consumes the benefits provided. Revenues are primarily variable as they are subject to customer's usage requirements; however, certain contracts mandate a delivery of a set quantity of electricity at a predetermined price, resulting in a fixed performance obligation.

Payment terms under marketing arrangements typically follow standard Edison Electric Institute and International Swaps and Derivatives Association terms, which call for payment in 20 days. Payments for competitive retail and offtake arrangements for renewable assets range from 15 to 60 days and are dependent on the product sold, location and the creditworthiness of customer. Invoices for marketing arrangements, competitive retail and offtake arrangements for renewable assets are issued monthly.

Fixed Performance Obligations

The following table represents the Registrants' remaining fixed performance obligations satisfied over time as of December 31, 2018. Fixed performance obligations primarily include wholesale transmission services, electricity sales for fixed amounts of energy and stand ready services into PJM's RPM market. The Registrant Subsidiaries amounts shown in the table below include affiliated and nonaffiliated revenues.

Company	2019	2020-2021	2022-2023	After 2024	Total
			(in millions)		
AEP	$ 920.7	$ 173.7	$ 162.5	$ 266.3	$ 1,523.2
AEP Texas	332.8	—	—	—	332.8
AEPTCo	893.6	—	—	—	893.6
APCo	144.8	32.2	23.2	—	200.2
I&M	25.6	2.9	2.9	—	31.4
OPCo	65.4	—	—	—	65.4
PSO	17.3	—	—	—	17.3
SWEPCo	35.2	—	—	—	35.2

Contract Assets and Liabilities

Contract assets are recognized when the Registrants have a right to consideration that is conditional upon the occurrence of an event other than the passage of time, such as future performance under a contract. The Registrants did not have any material contract assets as of December 31, 2018.

When the Registrants receive consideration, or such consideration is unconditionally due from a customer prior to transferring goods or services to the customer under the terms of a sales contract, they recognize a contract liability on the balance sheet in the amount of that consideration. Revenue for such consideration is subsequently recognized

in the period or periods in which the remaining performance obligations in the contract are satisfied. The Registrants' contract liabilities typically arise from services provided under joint use agreements for utility poles. The Registrants did not have any material contract liabilities as of December 31, 2018.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on the Registrants' balance sheets within the Accounts Receivable - Customers line item. The Registrants' balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Accounts Receivable - Customers were not material as of December 31, 2018. See "Securitized Accounts Receivable - AEP Credit" section of Note 14 for additional information.

The following table represents the amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable - Affiliated Companies on the Registrant Subsidiaries' balance sheets:

Company	December 31, 2018	January 1, 2018
	(in millions)	
AEPTCo	$ 58.6	$ 47.1
APCo	52.5	35.6
I&M	35.3	15.1
OPCo	46.1	26.1
PSO	12.4	6.1
SWEPCo	16.3	11.0

Contract Costs

Contract costs to obtain or fulfill a contract for AEP subsidiaries within the Generation & Marketing segment are accounted for under the guidance for "Other Assets and Deferred Costs" and presented as a single asset and are neither bifurcated nor reclassified between current and noncurrent assets on the Registrants' balance sheets. Contract costs to acquire a contract are amortized in a manner consistent with the transfer of goods or services to the customer in Other Operation on the Registrants' income statements. The Registrants did not have material contract costs as of December 31, 2018.

21. UNAUDITED QUARTERLY FINANCIAL INFORMATION

The disclosures in this note apply to all Registrants unless indicated otherwise.

In management's opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of the results of operations for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. The unaudited quarterly financial information for each Registrant is as follows:

Quarterly Periods Ended:	AEP	AEP Texas	AEPTCo (a)	APCo	I&M	OPCo	PSO	SWEPCo
				(in millions)				
March 31, 2018								
Total Revenues	$ 4,048.3	$ 371.6	$ 191.7	$ 820.4	$ 576.8	$ 790.9	$ 336.8	$ 419.4
Operating Income	706.0	81.8	111.1	193.0	97.4	117.3	3.9	41.6
Net Income (Loss)	456.7	46.8	84.1	125.5	64.2	79.6	(7.2)	13.4
Earnings Attributable to Common Shareholders	454.4	NA	NA	NA	NA	NA	NA	11.8
June 30, 2018								
Total Revenues	$ 4,013.2	$ 388.3	$ 200.1	$ 667.0	$ 589.7	$ 748.8	$ 398.3	$ 457.1
Operating Income	757.0	86.2	110.5	132.6	117.4	104.4	57.2	70.5
Net Income	530.1	46.5	82.0	77.4	94.7	68.8	36.6	38.7
Earnings Attributable to Common Shareholders	528.4	NA	NA	NA	NA	NA	NA	37.6
September 30, 2018								
Total Revenues	$ 4,333.1	$ 433.4	$ 194.4	$ 762.0	$ 629.7	$ 778.3	$ 481.4	$ 535.3
Operating Income	668.6	94.0	97.0	49.8	110.2	79.9	78.5	127.1
Net Income	579.7	57.8	78.1	87.1	72.7	88.7	60.4	89.6
Earnings Attributable to Common Shareholders	577.6	NA	NA	NA	NA	NA	NA	88.2
December 31, 2018								
Total Revenues	$ 3,801.1	$ 402.0	$ 189.9	$ 718.1	$ 574.5	$ 745.4	$ 330.8	$ 410.1
Operating Income	551.1	84.3	91.5	108.1	52.2	118.2	2.9	38.5
Net Income (Loss)	364.8	60.2	71.7	77.8	29.7	88.4	(6.6)	10.5
Earnings Attributable to Common Shareholders	363.4	NA	NA	NA	NA	NA	NA	9.6

Quarterly Periods Ended:	AEP	AEP Texas	AEPTCo	APCo	I&M	OPCo	PSO	SWEPCo
	(in millions)							
March 31, 2017								
Total Revenues	$ 3,933.3	$ 343.6	$ 152.7	$ 792.8	$ 560.5	$ 746.1	$ 304.1	$ 401.3
Operating Income (b)	1,085.7	82.3	90.4	218.9	117.2	149.6	19.9	52.8
Net Income	594.2	33.3	57.0	110.6	68.4	86.2	4.8	17.3
Earnings Attributable to Common Shareholders	592.2	NA	NA	NA	NA	NA	NA	16.3
June 30, 2017								
Total Revenues	$ 3,576.5	$ 389.5	$ 229.4	$ 675.3	$ 467.3	$ 663.9	$ 344.7	$ 424.7
Operating Income (b)	733.3	108.8	165.4	126.1	33.6	118.5	45.3	74.1
Net Income	376.2	49.0	107.4	52.1	10.5	62.3	20.4	25.1
Earnings Attributable to Common Shareholders	375.0	NA	NA	NA	NA	NA	NA	24.5
September 30, 2017								
Total Revenues	$ 4,104.7	$ 431.2	$ 165.6	$ 719.3	$ 557.7	$ 742.0	$ 442.8	$ 517.6
Operating Income (b)	975.1	128.8	93.6	171.7	113.6	153.4	85.9	136.0
Net Income	556.7	64.3	58.6	86.0	64.9	82.6	46.2	84.1
Earnings Attributable to Common Shareholders	544.7	NA	NA	NA	NA	NA	NA	73.1
December 31, 2017								
Total Revenues	$ 3,810.4	$ 374.1	$ 159.2	$ 746.8	$ 535.7	$ 731.9	$ 335.6	$ 436.3
Operating Income (b)	730.9	96.2	83.5	173.6	82.8	144.2	20.4	41.1
Net Income	401.8	163.9	47.7	82.6	42.9	92.8	0.6	11.0
Earnings Attributable to Common Shareholders	400.7	NA	NA	NA	NA	NA	NA	10.8

NA Not applicable.

(a) The amounts presented for the Quarterly Periods Ended March 31, 2018 and June 30, 2018 reflect the revisions made to AEPTCo's previously issued financial statements. See the "Revisions to Previously issued Financial Statement" section of Note 1.

(b) Amounts reflect the adoption of ASU 2017-07 "Compensation - Retirement Benefits". See Note 2 - New Accounting Pronouncements for additional information.

AEP

The unaudited quarterly financial information relating to Common Shareholders is as follows:

	2018 Quarterly Periods Ended			
	March 31	**June 30**	**September 30**	**December 31**
Earnings Attributable to AEP Common Shareholders (in millions)	$ 454.4	$ 528.4	$ 577.6	$ 363.4
Basic Earnings per Share Attributable to AEP Common Shareholders from Continuing Operations (a)	0.92	1.07	1.17	0.74
Diluted Earnings per Share Attributable to AEP Common Shareholders from Continuing Operations (a)	0.92	1.07	1.17	0.74

	2017 Quarterly Periods Ended			
	March 31	**June 30**	**September 30**	**December 31**
Earnings Attributable to AEP Common Shareholders (in millions)	$ 592.2	$ 375.0	$ 544.7	$ 400.7
Basic Earnings per Share Attributable to AEP Common Shareholders from Continuing Operations (a)	1.20	0.76	1.11	0.81
Diluted Earnings per Share Attributable to AEP Common Shareholders from Continuing Operations (a)	1.20	0.76	1.10	0.81

(a) Quarterly Earnings per Share amounts are intended to be stand-alone calculations and are not always additive to full-year amount due to rounding.

Subsidiaries of
American Electric Power Company, Inc.
As of December 31, 2018

Each company shown indented is a subsidiary of the company immediately above which is not indented to the same degree. Subsidiaries not indented are directly owned by American Electric Power Company, Inc.

Name of Company	Location of Incorporation
American Electric Power Service Corporation	New York
AEP Energy Supply LLC	Delaware
AEP Generation Resources Inc.	Delaware
AEP Generating Company	Ohio
AEP Transmission Holding Company, LLC	Delaware
AEP Transmission Company, LLC	Delaware
AEP Texas Inc.	Delaware
AEP Texas Central Transition Funding II LLC	Delaware
AEP Texas Central Transition Funding III LLC	Delaware
AEP Texas North Generation Company LLC	Delaware
Appalachian Power Company	Virginia
Appalachian Consumer Rate Relief Funding LLC	Delaware
Indiana Michigan Power Company	Indiana
Kentucky Power Company	Kentucky
Kingsport Power Company	Virginia
Ohio Power Company	Ohio
Ohio Phase-In-Recovery Funding LLC	Delaware
Ohio Valley Electric Corporation	Ohio
Indiana-Kentucky Electric Corporation	Indiana
Public Service Company of Oklahoma	Oklahoma
Southwestern Electric Power Company	Delaware
Wheeling Power Company	West Virginia

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-222068 and 333-221520) and on Form S-8 (Nos. 333-224973, 333-204557, 333-178044) of American Electric Power Company, Inc. of our report dated February 21, 2019 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in the 2018 Annual Report to Shareholders, which is incorporated by reference in this Annual Report on Form 10-K. We also consent to the incorporation by reference of our report dated February 21, 2019 relating to the financial statement schedules, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 21, 2019

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (Nos. 333-225325) of AEP Transmission Company, LLC of our report dated February 21, 2019 relating to the financial statements, which appears in the 2018 Annual Report, which is incorporated by reference in this Annual Report on Form 10-K. We also consent to the incorporation by reference of our report dated February 21, 2019 relating to the financial statement schedule, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 21, 2019

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-214448) of Appalachian Power Company of our report dated February 21, 2019 relating to the financial statements, which appears in the 2018 Annual Report to Shareholders, which is incorporated by reference in this Annual Report on Form 10-K.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 21, 2019

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-225103) of Indiana Michigan Power Company of our report dated February 21, 2019 relating to the financial statements, which appears in the 2018 Annual Report to Shareholders, which is incorporated by reference in this Annual Report on Form 10-K.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 21, 2019

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-211192) of Ohio Power Company of our report dated February 21, 2019 relating to the financial statements, which appears in the 2018 Annual Report to Shareholders, which is incorporated by reference in this Annual Report on Form 10-K.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 21, 2019

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-226856) of Southwestern Electric Power Company of our report dated February 21, 2019 relating to the financial statements, which appears in the 2018 Annual Report to Shareholders, which is incorporated by reference in this Annual Report on Form 10-K.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 21, 2019

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-204557, 333-224973, and 333-178044 on Form S-8 and Registration Statement Nos. 333-221520 and 333-222068 on Form S-3 of our reports dated February 27, 2017, relating to the consolidated financial statements and financial statement schedules of American Electric Power Company, Inc. and subsidiary companies (the “Company”), appearing in or incorporated by reference in this Annual Report on Form 10-K of American Electric Power Company, Inc. for the year ended December 31, 2018.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 21, 2019

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-225325 on Form S-3 of our report dated April 4, 2017, relating to the consolidated financial statements and financial statement schedule of AEP Transmission Company, LLC and subsidiaries, appearing in or incorporated by reference in this Annual Report on Form 10-K of AEP Transmission Company, LLC for the year ended December 31, 2018.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 21, 2019

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-214448 on Form S-3 of our report dated February 27, 2017, relating to the consolidated financial statements of Appalachian Power Company and subsidiaries appearing in or incorporated by reference in the Annual Report on Form 10-K of Appalachian Power Company for the year ended December 31, 2018.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 21, 2019

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-225103 on Form S-3 of our report dated February 27, 2017, relating to the consolidated financial statements of Indiana Michigan Power Company and subsidiaries appearing in or incorporated by reference in the Annual Report on Form 10-K of Indiana Michigan Power Company for the year ended December 31, 2018.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 21, 2019

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-211192 on Form S-3 of our report dated February 27, 2017, relating to the consolidated financial statements of Ohio Power Company and subsidiaries appearing in or incorporated by reference in the Annual Report on Form 10-K of Ohio Power Company for the year ended December 31, 2018.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 21, 2019

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-226856 on Form S-3 of our report dated February 27, 2017, relating to the consolidated financial statements of Southwestern Electric Power Company and subsidiaries appearing in or incorporated by reference in the Annual Report on Form 10-K of Southwestern Electric Power Company for the year ended December 31, 2018.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 21, 2019

POWER OF ATTORNEY

AMERICAN ELECTRIC POWER COMPANY, INC.

Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2018

The undersigned directors of AMERICAN ELECTRIC POWER COMPANY, INC., a New York corporation (the "Company"), do hereby constitute and appoint NICHOLAS K. AKINS, JULIA A. SLOAT and BRIAN X. TIERNEY, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2018, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF the undersigned have hereunto set their hands this 13th day of February, 2019.

/s/ Nicholas K. Akins
Nicholas K. Akins

/s/ David J. Anderson
David J. Anderson

/s/ J. Barnie Beasley, Jr.
J. Barnie Beasley, Jr.

/s/ Ralph D. Crosby, Jr.
Ralph D. Crosby, Jr.

/s/ Linda A. Goodspeed
Linda A. Goodspeed

/s/ Thomas E. Hoaglin
Thomas E. Hoaglin

/s/ Sandra Beach Lin
Sandra Beach Lin

/s/ Richard C. Notebaert
Richard C. Notebaert

/s/ Lionell L. Nowell, III
Lionel L. Nowell, III

/s/ Stephen S. Rasmussen
Stephen S. Rasmussen

/s/ Oliver G. Richard, III
Oliver G. Richard, III

/s/ Sara Martinez Tucker
Sara Martinez Tucker

POWER OF ATTORNEY

AEP TRANSMISSION COMPANY, LLC

Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2018

The undersigned managers of AEP TRANSMISSION COMPANY, LLC, a Delaware limited liability company (the "Company"), do hereby constitute and appoint NICHOLAS K. AKINS, JULIA A. SLOAT and BRIAN X. TIERNEY, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2018, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF the undersigned have hereunto set their hands this 13th day of February, 2019.

/s/ Nicholas K. Akins
Nicholas K. Akins

/s/ David M. Feinberg
David M. Feinberg

/s/ Mark C. McCullough
Mark C. McCullough

/s/ A. Wade Smith
A.Wade Smith

/s/ Brian X. Tierney
Brian X. Tierney

POWER OF ATTORNEY
Annual Report on Form 10-K for the Fiscal Year Ended
December 31, 2018

The undersigned directors of the following companies (each respectively the "Company")

Company	State of Incorporation
AEP Texas Inc.	Delaware
Appalachian Power Company	Virginia
Ohio Power Company	Ohio
Public Service Company of Oklahoma	Oklahoma
Southwestern Electric Power Company	Delaware

do hereby constitute and appoint NICHOLAS K. AKINS, JULIA A. SLOAT and BRIAN X. TIERNEY, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2018, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF the undersigned have hereunto set their hands this 13th day of February, 2019.

/s/ Nicholas K. Akins
Nicholas K. Akins

/s/ Lisa M. Barton
Lisa M. Barton

/s/ Paul Chodak, III
Paul Chodak, III

/s/ David M. Feinberg
David M. Feinberg

/s/ Lana L. Hillebrand
Lana L. Hillebrand

/s/ Mark C. McCullough
Mark C. McCullough

/s/ Charles R. Patton
Charles R. Patton

/s/ Brian X. Tierney
Brian X. Tierney

POWER OF ATTORNEY
Annual Report on Form 10-K for the Fiscal Year Ended
December 31, 2018

The undersigned directors of the following companies (each respectively the "Company")

Company	State of Incorporation
AEP Texas Inc.	Delaware
Appalachian Power Company	Virginia
Ohio Power Company	Ohio
Public Service Company of Oklahoma	Oklahoma
Southwestern Electric Power Company	Delaware

do hereby constitute and appoint NICHOLAS K. AKINS, JULIA A. SLOAT and BRIAN X. TIERNEY, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2018, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF the undersigned have hereunto set their hands this 13th day of February, 2019.

/s/ Nicholas K. Akins
Nicholas K. Akins

/s/ Lisa M. Barton
Lisa M. Barton

/s/ Paul Chodak, III
Paul Chodak, III

/s/ David M. Feinberg
David M. Feinberg

/s/ Lana L. Hillebrand
Lana L. Hillebrand

/s/ Mark C. McCullough
Mark C. McCullough

/s/ Charles R. Patton
Charles R. Patton

/s/ Brian X. Tierney
Brian X. Tierney

POWER OF ATTORNEY

INDIANA MICHIGAN POWER COMPANY

Annual Report on Form 10-K for the Fiscal Year Ended December 31, 2018

The undersigned directors of INDIANA MICHIGAN POWER COMPANY, an Indiana corporation (the "Company"), do hereby constitute and appoint NICHOLAS K. AKINS, JULIA A. SLOAT and BRIAN X. TIERNEY, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2018, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF the undersigned have hereunto set their hands this 13th day of February, 2019.

/s/ Nicholas K. Akins
Nicholas K. Akins

/s/ Lisa M. Barton
Lisa M. Barton

/s/ Nicholas M. Elkins
Nicholas M. Elkins

/s/ Thomas A. Kratt
Thomas A. Kratt

/s/ Marc E. Lewis
Marc E. Lewis

/s/ David A. Lucas
David A. Lucas

/s/ Mark C. McCullough
Mark C. McCullough

/s/ Carla E. Simpson
Carla E. Simpson

/s/ Toby L. Thomas
Toby L. Thomas

/s/ Brian X. Tierney
Brian X. Tierney

POWER OF ATTORNEY
Annual Report on Form 10-K for the Fiscal Year Ended
December 31, 2018

The undersigned directors of the following companies (each respectively the "Company")

Company	State of Incorporation
AEP Texas Inc.	Delaware
Appalachian Power Company	Virginia
Ohio Power Company	Ohio
Public Service Company of Oklahoma	Oklahoma
Southwestern Electric Power Company	Delaware

do hereby constitute and appoint NICHOLAS K. AKINS, JULIA A. SLOAT and BRIAN X. TIERNEY, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2018, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF the undersigned have hereunto set their hands this 13th day of February, 2019.

/s/ Nicholas K. Akins
Nicholas K. Akins

/s/ Lisa M. Barton
Lisa M. Barton

/s/ Paul Chodak, III
Paul Chodak, III

/s/ David M. Feinberg
David M. Feinberg

/s/ Lana L. Hillebrand
Lana L. Hillebrand

/s/ Mark C. McCullough
Mark C. McCullough

/s/ Charles R. Patton
Charles R. Patton

/s/ Brian X. Tierney
Brian X. Tierney

POWER OF ATTORNEY
Annual Report on Form 10-K for the Fiscal Year Ended
December 31, 2018

The undersigned directors of the following companies (each respectively the "Company")

Company	State of Incorporation
AEP Texas Inc.	Delaware
Appalachian Power Company	Virginia
Ohio Power Company	Ohio
Public Service Company of Oklahoma	Oklahoma
Southwestern Electric Power Company	Delaware

do hereby constitute and appoint NICHOLAS K. AKINS, JULIA A. SLOAT and BRIAN X. TIERNEY, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2018, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF the undersigned have hereunto set their hands this 13th day of February, 2019.

/s/ Nicholas K. Akins
Nicholas K. Akins

/s/ Lisa M. Barton
Lisa M. Barton

/s/ Paul Chodak, III
Paul Chodak, III

/s/ David M. Feinberg
David M. Feinberg

/s/ Lana L. Hillebrand
Lana L. Hillebrand

/s/ Mark C. McCullough
Mark C. McCullough

/s/ Charles R. Patton
Charles R. Patton

/s/ Brian X. Tierney
Brian X. Tierney

POWER OF ATTORNEY
Annual Report on Form 10-K for the Fiscal Year Ended
December 31, 2018

The undersigned directors of the following companies (each respectively the "Company")

Company	State of Incorporation
AEP Texas Inc.	Delaware
Appalachian Power Company	Virginia
Ohio Power Company	Ohio
Public Service Company of Oklahoma	Oklahoma
Southwestern Electric Power Company	Delaware

do hereby constitute and appoint NICHOLAS K. AKINS, JULIA A. SLOAT and BRIAN X. TIERNEY, and each of them, their attorneys-in-fact and agents, to execute for them, and in their names, and in any and all of their capacities, the Annual Report of the Company on Form 10-K, pursuant to Section 13 of the Securities Exchange Act of 1934, for the fiscal year ended December 31, 2018, and any and all amendments thereto, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform every act and thing required or necessary to be done, as fully to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF the undersigned have hereunto set their hands this 13th day of February, 2019.

/s/ Nicholas K. Akins
Nicholas K. Akins

/s/ Lisa M. Barton
Lisa M. Barton

/s/ Paul Chodak, III
Paul Chodak, III

/s/ David M. Feinberg
David M. Feinberg

/s/ Lana L. Hillebrand
Lana L. Hillebrand

/s/ Mark C. McCullough
Mark C. McCullough

/s/ Charles R. Patton
Charles R. Patton

/s/ Brian X. Tierney
Brian X. Tierney

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Nicholas K. Akins, certify that:

1. I have reviewed this report on Form 10-K of American Electric Power Company, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2019 By: /s/ Nicholas K. Akins

Nicholas K. Akins
Chief Executive Officer

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Nicholas K. Akins, certify that:

1. I have reviewed this report on Form 10-K of AEP Transmission Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2019 By: /s/ Nicholas K. Akins

Nicholas K. Akins
Chief Executive Officer

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Nicholas K. Akins, certify that:

1. I have reviewed this report on Form 10-K of AEP Texas Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2019 By: /s/ Nicholas K. Akins

Nicholas K. Akins
Chief Executive Officer

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Nicholas K. Akins, certify that:

1. I have reviewed this report on Form 10-K of Appalachian Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2019 By: /s/ Nicholas K. Akins

Nicholas K. Akins
Chief Executive Officer

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Nicholas K. Akins, certify that:

1. I have reviewed this report on Form 10-K of Indiana Michigan Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2019

By: /s/ Nicholas K. Akins

Nicholas K. Akins
Chief Executive Officer

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Nicholas K. Akins, certify that:

1. I have reviewed this report on Form 10-K of Ohio Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2019 By: /s/ Nicholas K. Akins

Nicholas K. Akins
Chief Executive Officer

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Nicholas K. Akins, certify that:

1. I have reviewed this report on Form 10-K of Public Service Company of Oklahoma;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2019 By: /s/ Nicholas K. Akins

Nicholas K. Akins
Chief Executive Officer

EXHIBIT 31(a)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Nicholas K. Akins, certify that:

1. I have reviewed this report on Form 10-K of Southwestern Electric Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2019 By: /s/ Nicholas K. Akins

Nicholas K. Akins
Chief Executive Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Brian X. Tierney, certify that:

1. I have reviewed this report on Form 10-K of American Electric Power Company, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2019

By:

/s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Brian X. Tierney, certify that:

1. I have reviewed this report on Form 10-K of AEP Transmission Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2019

By: /s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Brian X. Tierney, certify that:

1. I have reviewed this report on Form 10-K of AEP Texas Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2019

By: /s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Brian X. Tierney, certify that:

1. I have reviewed this report on Form 10-K of Appalachian Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2019

By: /s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Brian X. Tierney, certify that:

1. I have reviewed this report on Form 10-K of Indiana Michigan Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2019

By:

/s/ Brian X. Tierney
Brian X. Tierney

Chief Financial Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Brian X. Tierney, certify that:

1. I have reviewed this report on Form 10-K of Ohio Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2019

By: /s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Brian X. Tierney, certify that:

1. I have reviewed this report on Form 10-K of Public Service Company of Oklahoma;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2019

By: /s/ Brian X. Tierney
Brian X. Tierney

Chief Financial Officer

EXHIBIT 31(b)
CERTIFICATION PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Brian X. Tierney, certify that:

1. I have reviewed this report on Form 10-K of Southwestern Electric Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of each registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting that are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2019

By:

/s/ Brian X. Tierney
Brian X. Tierney

Chief Financial Officer

Exhibit 32(a)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of American Electric Power Company, Inc. (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof, I, Nicholas K. Akins, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Nicholas K. Akins
Nicholas K. Akins
Chief Executive Officer

February 21, 2019

A signed original of this written statement required by Section 906 has been provided to American Electric Power Company, Inc. and will be retained by American Electric Power Company, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(a)

This Certification is being furnished and shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of AEP Transmission Company, LLC (the “Company”) on Form 10-K (the “Report”) for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof, I, Nicholas K. Akins, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Nicholas K. Akins
Nicholas K. Akins
Chief Executive Officer

February 21, 2019

A signed original of this written statement required by Section 906 has been provided to AEP Transmission Company, LLC and will be retained by AEP Transmission Company, LLC and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(a)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of AEP Texas Inc. (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof, I, Nicholas K. Akins, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Nicholas K. Akins
Nicholas K. Akins
Chief Executive Officer

February 21, 2019

A signed original of this written statement required by Section 906 has been provided to AEP Texas Inc. and will be retained by AEP Texas Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(a)

This Certification is being furnished and shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of Appalachian Power Company (the “Company”) on Form 10-K (the “Report”) for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof, I, Nicholas K. Akins, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Nicholas K. Akins
Nicholas K. Akins
Chief Executive Officer

February 21, 2019

A signed original of this written statement required by Section 906 has been provided to Appalachian Power Company and will be retained by Appalachian Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(a)

This Certification is being furnished and shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of Indiana Michigan Power Company (the “Company”) on Form 10-K (the “Report”) for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof, I, Nicholas K. Akins, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Nicholas K. Akins
Nicholas K. Akins
Chief Executive Officer

February 21, 2019

A signed original of this written statement required by Section 906 has been provided to Indiana Michigan Power Company and will be retained by Indiana Michigan Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(a)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of Ohio Power Company (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof, I, Nicholas K. Akins, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Nicholas K. Akins
Nicholas K. Akins
Chief Executive Officer

February 21, 2019

A signed original of this written statement required by Section 906 has been provided to Ohio Power Company and will be retained by Ohio Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(a)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of Public Service Company of Oklahoma (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof, I, Nicholas K. Akins, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Nicholas K. Akins
Nicholas K. Akins
Chief Executive Officer

February 21, 2019

A signed original of this written statement required by Section 906 has been provided to Public Service Company of Oklahoma and will be retained by Public Service Company of Oklahoma and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(a)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of Southwestern Electric Power Company (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof, I, Nicholas K. Akins, the chief executive officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Nicholas K. Akins
Nicholas K. Akins
Chief Executive Officer

February 21, 2019

A signed original of this written statement required by Section 906 has been provided to Southwestern Electric Power Company and will be retained by Southwestern Electric Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of American Electric Power Company, Inc. (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof, I, Brian X. Tierney, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

February 21, 2019

A signed original of this written statement required by Section 906 has been provided to American Electric Power Company, Inc. and will be retained by American Electric Power Company, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of AEP Transmission Company, LLC (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof, I, Brian X. Tierney, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

February 21, 2019

A signed original of this written statement required by Section 906 has been provided to AEP Transmission Company, LLC and will be retained by AEP Transmission Company, LLC and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of AEP Texas Inc. (the “Company”) on Form 10-K (the “Report”) for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof, I, Brian X. Tierney, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

February 21, 2019

A signed original of this written statement required by Section 906 has been provided to AEP Texas Inc. and will be retained by AEP Texas Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of Appalachian Power Company (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof, I, Brian X. Tierney, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

February 21, 2019

A signed original of this written statement required by Section 906 has been provided to Appalachian Power Company and will be retained by Appalachian Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of Indiana Michigan Power Company (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof, I, Brian X. Tierney, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

February 21, 2019

A signed original of this written statement required by Section 906 has been provided to Indiana Michigan Power Company and will be retained by Indiana Michigan Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of Ohio Power Company (the “Company”) on Form 10-K (the “Report”) for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof, I, Brian X. Tierney, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

February 21, 2019

A signed original of this written statement required by Section 906 has been provided to Ohio Power Company and will be retained by Ohio Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of Public Service Company of Oklahoma (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof, I, Brian X. Tierney, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

February 21, 2019

A signed original of this written statement required by Section 906 has been provided to Public Service Company of Oklahoma and will be retained by Public Service Company of Oklahoma and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32(b)

This Certification is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This Certification shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, except as otherwise stated in such filing.

Certification Pursuant to Section 1350 of Chapter 63
of Title 18 of the United States Code

In connection with the Annual Report of Southwestern Electric Power Company (the "Company") on Form 10-K (the "Report") for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof, I, Brian X. Tierney, the chief financial officer of the Company certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 that, based on my knowledge (i) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Brian X. Tierney
Brian X. Tierney
Chief Financial Officer

February 21, 2019

A signed original of this written statement required by Section 906 has been provided to Southwestern Electric Power Company and will be retained by Southwestern Electric Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

MINE SAFETY INFORMATION

The Federal Mine Safety and Health Act of 1977 (Mine Act) imposes stringent health and safety standards on various mining operations. The Mine Act and its related regulations affect numerous aspects of mining operations, including training of mine personnel, mining procedures, equipment used in mine emergency procedures, mine plans and other matters. SWEPCo, through its ownership of Dolet Hills Lignite Company (DHLC), a wholly-owned lignite mining subsidiary of SWEPCo, is subject to the provisions of the Mine Act.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires companies that operate mines to include in their periodic reports filed with the SEC, certain mine safety information covered by the Mine Act. DHLC received the following notices of violation and proposed assessments under the Mine Act for the quarter-ended December 31, 2018:

Number of Citations for S&S Violations of Mandatory Health or Safety Standards under 104 *		0
Number of Orders Issued under 104(b) *		0
Number of Citations and Orders for Unwarrantable Failure to Comply with Mandatory Health or Safety Standards under 104(d) *		0
Number of Flagrant Violations under 110(b)(2) *		0
Number of Imminent Danger Orders Issued under 107(a)		0
Total Dollar Value of Proposed Assessments	$	—
Number of Mining-related Fatalities		0

* References to sections under the Mine Act.

There are currently no legal actions pending before the Federal Mine Safety and Health Review Commission.

Explanation: List showing the standard journal entries prepared monthly by the utility with a description of what each entry records.

Line No.	Business Unit	Journal ID	Frequency	Journal Entry Description
1	111	FERC668RCL	M	Monthly reclass of RTO related computer and communication expenses, per FERC 668
2	111	GL0054	M	ADJ W/C ACCR FOR ADMITTED & PR
3	111	LTDFCFEES	M	Amortize Issuance Cost for SWEPCO Credit Facility due 7-11-2017
4	111	LTDINTPAY	M07	UNBUNDLE INTEREST PAYMENT
5	111	LTDISSEXP	W	ISSUANCE EXPENSES
6	111	LTDMONTHLY	M	MONTHLY BOND ACCRUALS AND AMOR
7	111	TXRCS16INC	M	Reclass Intercompany Charges.
8	111	TXRCS16INC	M	Reclass Intercompany Charges.
9	159	AJE_PY_ACC	M	Reclass Project FAN102853 to accounts 5000000, 5010000, 5060000 BU 166; account 5660000 BU 192 & account 5880000 BU 119; AEPSC Bill incorrected charged to various BU's and accounts. Caused by labor accrual process.
10	159	AJESCBBIL	M	Reclass AEPSC charges
11	159	ALERTAMORT	M	To Amortize Exact Target Customer Alert System Prepaid for 12 month Period, beginning June 2017.
12	159	CITYMAINAM	M	To Amortize the 2016 Deferral per June 1, 2017 Louisiana FRP Filing. Amortization period is May 2017 - July 2018.
13	159	CITYMAINTL	M	To defer O&M expenses related to the City of Shreveport Sewer work for future recovery and to calculate Carrying Charges at the fuel over/under interest rate of 3.50% per LPSC Dkt# U-32220 February 2016.
14	159	CRD030	M	Factoring entry to record the net a/r factored, bad debt expense, carrying cost expense, credit line fee expense, agency fees and 2% charge offs for the current month.
15	159	CRD031	M	Record prepaid carrying cost for the current month activity.
16	159	FC012	M	FUEL TRUE-UP ENTRIES
17	159	FC052	M	Base/fuel entreis for Arkansas and Louisiana
18	159	FC096	M	TO RECORD THE SWEPCO ARKANSAS ENERGY EFFICIENCY OVER/UNDER.
19	159	FC096LA	M	TO RECORD THE SWEPCO LOUISIANA QUICK START ENERGY EFFICIENCY OVER/UNDER FOR CURRENT MONTH. LOUISIANA DOCKET R-31106
20	159	FCLAFRP09	M	To amortize the 2009 over-refund over 15 months starting in May 2017. Docket No. U-23327
21	159	GL0054	M	ADJ WC RESERVES BASED ON CANNON COCHRAN MANAGEMENT SERVICES & EAST COAST RISK MANAGEMENT REPORT FOR CURRENT MONTH.
22	159	GL0306	M	Clear Parking Expense from 2420005
23	159	LTDFCFEES	M	Amortize Issuance Cost for SWEPCO Credit Facility due 7-11-2017
24	159	LTDINTPAY	M07	UNBUNDLE INTEREST PAYMENT
25	159	LTDISSEXP	W	ISSUANCE EXPENSES
26	159	LTDMONTHLY	M	MONTHLY BOND ACCRUALS AND AMOR
27	159	LTDTREASRV	M	REVERSE MONTHLY ACCRUALS
28	159	PPINSUR	M	AMORTIZE PREPAID INSURANCE-VAR
29	159	RCSETXBASE	M	Deferral of Texas Rate Case Docket# 40443 expenses to Reg Asset 1823108.
30	159	SCB_AEPCRD	M	TO RECLASS SCB NOVEMBER CHARGES BILLED TO AEP CREDIT FOR TREASURY FACTORING DATABASE (CWIP) THAT SHOULD BE BILLED TO BENEFITTING DISTRIBUTION COMPANIES.
31	159	SEPAFDCPEN	M	AFUDC on the portion of the pension prepayment asset ruled to be CWIP in PUCT Docket No. 40443.
32	159	VEGETATION	M	Current month Louisiana SQIP Over/Under (Per LPSC Dkt U-32220) and reclass between Earnings offset and NonEarnings offset.
33	161	AJE_PY_ACC	M	Reclass Project FAN102853 to accounts 5000000, 5010000, 5060000 BU 166; account 5660000 BU 192 & account 5880000 BU 119; AEPSC Bill incorrected charged to various BU's and accounts. Caused by labor accrual process.
34	161	AJESCBBIL	M	Reclass AEPSC charges

Explanation: List showing the standard journal entries prepared monthly by the utility with a description of what each entry records.

Line No.	Business Unit	Journal ID	Frequency	Journal Entry Description
35	161	CRD030	M	Factoring entry to record the net a/r factored, bad debt expense, carrying cost expense, credit line fee expense, agency fees and 2% charge offs for the current month.
36	161	CRD031	M	Record prepaid carrying cost for the current month activity.
37	161	EXCESSEARN	M	Excess Earnings amortization resulting from settlement of SWEPCO Texas Base Rate Case, PUCT Docket No. 37364. Amortization starts May 2010 and runs through April 2054.
38	161	FC052	M	Base/fuel entreis for Texas
39	161	FC096	M	SWEPCO TX DSM (Demand Side Management) Over/(Under) Program Recovery. Docket 36281.
40	161	FCTXTRR	M	To recognize the incremental revenue earned in January 2018, as a result of implementing the Final Order, compared to the base rates SWEPCO had billed during this same period. PUCT Docket No. 46449.
41	161	FCTXTRR	M	To reverse the surcharge revenues previously accrued for the relate back period and to recognize the equity portion of the carrying charge in the revenues billed during the current monthly as approved in the TRR surcharge tariff PUC Docket 47929.
42	161	GL0054	M	ADJ WC RESERVES BASED ON CANNON COCHRAN MANAGEMENT SERVICES & EAST COAST RISK MANAGEMENT REPORT FOR CURRENT MONTH.
43	161	GL0306	M	Clear Parking Expense from 2420005 (No Entry)
44	161	LTDFCFEES	M	Amortize Issuance Cost for SWEPCO Credit Facility due 7-11-2017
45	161	LTDINTPAY	M07	UNBUNDLE INTEREST PAYMENT
46	161	LTDISSEXP	W	ISSUANCE EXPENSES
47	161	LTDMONTHLY	M	MONTHLY BOND ACCRUALS AND AMOR
48	161	PPINSUR	M	AMORTIZE PREPAID INSURANCE-VAR
49	161	RCSETXAMOR	M	Recovery of Rate Case Expenses in PUCT Docket No. 42370 Amortization starting August 2015- July 2018. (3 Year Peiord).
50	161	RCSETXAMOR	M	Recovery of Rate Case Expenses in PUCT Docket No. 42370 Amortization starting August 2015- July 2018. (3 Year Peiord).
51	161	RCSETXBASE	M	Deferral of Texas Rate Case Docket# 40443 expenses to Reg Asset 1823108.
52	161	SCB_AEPCRD	M	TO RECLASS SCB NOVEMBER CHARGES BILLED TO AEP CREDIT FOR TREASURY FACTORING DATABASE (CWIP) THAT SHOULD BE BILLED TO BENEFITTING DISTRIBUTION COMPANIES.
53	161	SEPAFDCPEN	M	AFUDC on the portion of the pension prepayment asset ruled to be CWIP in PUCT Docket No. 40443.
54	161	SESCO_ALLO	Q	SESCO Superfund Allocation (WILL DO 10/11)
55	161	TXRCS16INC	M	Reclass Intercompany Charges.
56	161	TXRCS16INC	M	Reclass Intercompany Charges.
57	161	VEGETATION	M	Current Month Texas Vegetation Management per TX Docket# 40443.
58	168	AJE_PY_ACC	M	Reclass Project FAN102853 to accounts 5000000, 5010000, 5060000 BU 166; account 5660000 BU 192 & account 5880000 BU 119; AEPSC Bill incorrected charged to various BU's and accounts. Caused by labor accrual process.
59	168	CMFGEN	M	CENTRAL MACHINE FACILITY STATI
60	168	CMFSTAT	M	CENTRAL MACHINE FACILITY STATI
61	168	COALSWP	M	LIGNITE BILL FOR THE MONTH
62	168	DOLETARO	M	MOVE 50% OF DOLET'S FINAL AND PRE-EXISTING ARO TO SWEPCO, THAT IS THE PORTION SWEPCO WOULD BE RESPONSIBLE FOR IF DOLET WERE TO CEASE OPERATIONS
63	168	ENVIR_ACRL	W	ADJUST SHORT TERM AND LONG TERM ENVIRONMENTAL ACCRUALS FOR WELSH UNIT 1, SHORT TERM SHOULD HAVE ACCRUAL OF $25,000.
64	168	ENVIR_ACRL	Q	ADJUST ENVIRONMENTAL ACCRUALS FOR WELSH UNITS 1 & 3. UNIT 3 IS NOW COMPLETE AND UNIT 1 SHOULD HAVE ACCRUAL OF $50,560.
65	168	FC012	M	Deferred fuel entries
66	168	FC012ARK	M	Arkansas true-up entries
67	168	FC012EAC	M	Louisiana deferred EAC

Explanation: List showing the standard journal entries prepared monthly by the utility with a description of what each entry records.

Line No.	Business Unit	Journal ID	Frequency	Journal Entry Description
68	168	FC012ENV	M	To record the deferral of environmental costs for Arkansas, not approved to be included in the deferred fuel calculation at this time.
69	168	FC012LOU	M	Louisiana Interest entries
70	168	FC052	M	Base/fuel entries for wholesale
71	168	FC102	M	Monthly Mine Closing entries
72	168	FC812	M	Normal adjustments to prior period deferred fuel
73	168	FC812EAC	M	True-up of prior period EAC balance.
74	168	FCARTAX	M	
75	168	FCLAFRP15	M	
76	168	FCLATAX	M	To record income tax refund provision due to income tax rate change effective 1/1/18. In accordance with LPSC Special Order No 13-2018.
77	168	FCLATURK	M	To reclassify the refund provision from FERC account 229 to 242 for the current portion and 253 for the long term portion related to the TURK Prudence review settlement in December 2017 per LPSC Docket No. U-33856.
78	168	FCSEPEXCES	M	To record excess ADIT refund provision due to income tax rate change effective 1/25/18. In accordance with PUCT Order #47945, APSC Docket No 18-006-U No. 1 and LPSC Special Order No 13-2018.
79	168	FCTXTAX	M	To record income tax refund provision due to income tax rate change effective 1/25/18. In accordance with PUCT Order #47945.
80	168	GL0054	M	ADJ W/C ACCR FOR ADMITTED & PROBABLE (No entry Cur Mo)
81	168	INCOME	M	Mutual Energy of SWEPCo
82	168	LANDEPT	M	50% OF LAND DEPT EXPENSES
83	168	LTDFCFEES	M	Amortize Issuance Cost for SWEPCO Credit Facility due 7-11-2017
84	168	LTDINTPAY	M07	UNBUNDLE INTEREST PAYMENT
85	168	LTDISSEXP	W	ISSUANCE EXPENSES
86	168	LTDMONTHLY	M	MONTHLY BOND ACCRUALS AND AMOR
87	168	LTDTREASRV	M	REVERSE TREASURY INTEREST EXP ACCRUAL FOR SENIOR NOTES: C, D, E, F, G, H, AND Credit Facility - INTEREST ACCRUED AND UNBUNDLED MANUALLY ON LTDMONTHLY.
88	168	PPINSUR	M	AMORTIZE PREPAID INSURANCE-VAR
89	168	PREPAYAMRT	M	To amortize the outside services OSIsoft invoice (voucher#02023210 cllassified as a prepaid as a result of the January 2017 prepaid review. Amortization period is Jan-Dec 2017.
90	168	RCSETXBASE	M	Deferral of Texas Rate Case Docket# 40443 expenses to Reg Asset 1823108.
91	168	ROE_WHLSE	M	NUECES/SAN PATRICIO CO-OP MANUALLY BILLED TC1 CHARGES
92	168	SEPAFDCPEN	M	AFUDC on the portion of the pension prepayment asset ruled to be CWIP in PUCT Docket No. 40443.
93	168	SEPENVIRON	M	
94	168	SG11400	M	ALLIANCE RAILCAR BILLING
95	168	SG11401	M	RECLASS ALLIANCE FROM 1510001
96	168	SG11402	M	ALLIANCE RAILCAR FACILITY, MATERIAL, LABOR AND OVERHEAD CHARGES FOR REPAIRING AEPX I&M CARS.
97	168	SG16000	M	DOLET HILLS MONTHLY EARNINGS
98	168	SG18000	M	Sabine Invoice & Reclamation Adj for Elimination
99	168	STAL_AR_LA	M	RECLASS JLSTALL MONTHLY O&M CHARGES TO THE EARNINGS OFFSET PROJECTS FOR ARKANSAS 20.18% AND LOUISIANA 29.78%, PER REQUEST OF THE EARNINGS OFFSET TEAM
100	168	STALLPPAID	Q	To reclass the Siemens 6A Fall 2019 maintenance to the Long term prepaid account.
101	168	STALLRIDER	M	Current Month Deferral of the Over/Under collection of O&M expenses, depreciation, and carrying costs for the Arkansas jurisdictional portion of JLStall Unit 6 at Arsenal Hill per the Arkansas PSC Docket No. 09-008-U.
102	168	TXRCS16INC	M	Reclass Intercompany Charges.
103	168	TXRCS16INC	M	Reclass Intercompany Charges.

Southerwestern Electric Power Company **Schedule E-6**
Standard Journal Entries
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: List showing the standard journal entries prepared monthly by the utility with a description of what each entry records.

Line No.	Business Unit	Journal ID	Frequency	Journal Entry Description
104	168	WCAFUDCEXP	M	To expense current month costs related to the AFUDC Wind Catcher Project for Equity and Debt, from Capital to 432 & 4191 and from 432 & 4191 to 4265038.
105	168	WCEXPENSE	M	To expense current month costs related to the Wind Catcher Project from CWIP (a/c 1070001) to acct 4265035 for PSO and SWEPCO, using the contra work orders for the WC project.
106	168	WCSPLIT	M	To transfer SWEPCO's 70 percent ownership of the costs for August 2017 related to the Wind Catcher Project from PSO's ledger to SWEPCO's ledger.
107	168	WU2AMOR	M	To amortize Welsh Unit 2 Texas regulatory asset for the period May 20, 2017 through December 31, 2042 per Docket#46449
108	168	WU2AROAMOR	M	To Amortize Welsh Unit 2 ARO regulatory asset impairment per SWEPCo Texas Case Docket# 46449 - 24 years starting May 2017.
109	194	AJE_PY_ACC	M	Reclass Project FAN102853 to accounts 5000000, 5010000, 5060000 BU 166; account 5660000 BU 192 & account 5880000 BU 119; AEPSC Bill incorrected charged to various BU's and accounts. Caused by labor accrual process.
110	194	AJESCBBIL	M	Reclass AEPSC charges
111	194	ARKLAHOMA	Q-YR	Record Equity Earnings/Loss (Dec each yr)
112	194	FC133	M	HVDC EAST TIE MONTHLY O&M, INDIRECT OVERHEAD, LOAD DISPATCH, FACILITIES, AND INSURANCE
113	194	FC133F	Q	Quarterly Clearing HVDC East Tie
114	194	FERC668RCL	M	Monthly reclass of RTO related computer and communication expenses, per FERC 668
115	194	GL0054	M	ADJ W/C ACCR FOR ADMITTED & PROBABLE (No entry Cur Mo)
116	194	HVDCSWPBIL	M	TCC Billing SWEPCO 25% for Welsh HDVC tie. (WO Correction)
117	194	LTDFCFEES	M	Amortize Issuance Cost for SWEPCO Credit Facility due 7-11-2017
118	194	LTDINTPAY	M07	UNBUNDLE INTEREST PAYMENT
119	194	LTDISSEXP	W	ISSUANCE EXPENSES
120	194	LTDMONTHLY	M	MONTHLY BOND ACCRUALS AND AMOR
121	194	PPINSUR	M	AMORTIZE PREPAID INSURANCE-VAR
122	194	RCSETXBASE	M	Deferral of Texas Rate Case Docket# 40443 expenses to Reg Asset 1823108. (Last Entry 3/14)
123	194	SCBSNOLHVD	M	HVDC East Tie
124	194	SEPAFDCPEN	M	AFUDC on the portion of the pension prepayment asset ruled to be CWIP in PUCT Docket No. 40443.
125	194	SPPAMORT	M	To record amortization of withdrawn transmission projects regulatory asset over the May 2018 - April 2019 recovery period, per FERC ER18-748-001 SPP NTC Memo. Due to timing of receipt of the ord, SPP was unable to update the April RRR.
126	194	ZSWTRNS	M	Statistical entry for SWEPCo TX

Supporting Schedules:

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
1	1010001	Plant in Service	A. This account shall include the original cost of production plant (steam, nuclear, hydro and other), included in accounts 310 to 346, owned and used by the utility in its utility operations, and having an expectation of life in service of more than one year from date of installation, including such property owned by the utility but held by nominees. B. The cost of additions to and betterments of property leased from others, which are includible in this account, shall be recorded in subdivisions separate and distinct from those relating to owned property (Refer to Account 1011001). Effective 7/1/02 - the Account title was changed from "Plant in Service - Production" to "Plant in Service". The business units were unbundled between Generation, Transmission, Distribution, & Nuclear - so the detail was kept
2	1010002	Plant In Service-Transmission	A. This account shall include the original cost of transmission plant, included in accounts 350 to 359, owned and used by the utility in its utility operations, and having an expectation of life in service of more than one year from date of installation, including such property owned by the utility but held by nominees. B. The cost of additions to and betterments of property leased from others, which are includible in this account, shall be recorded in subdivisions separate and distinct from those relating to owned property (Refer to Account 1011002).
3	1010003	Plant In Service-Distribution	A. This account shall include the original cost of distribution plant, included in accounts 360 to 373, owned and used by the utility in its utility operations, and having an expectation of life in service of more than one year from date of installation, including such property owned by the utility but held by nominees. B. The cost of additions to and betterments of property leased from others, which are includible in this account, shall be recorded in subdivisions separate and distinct from those relating to owned property (Refer to Account 1011003).
4	1010004	Plant In Service - Gen & Misc	A. This account shall include the original cost of general and miscellaneous plant, included in accounts 389 to 399, owned and used by the utility in its utility operations, and having an expectation of life in service of more than one year from date of installation, including such property owned by the utility but held by nominees. B. The cost of additions to and betterments of property leased from others, which are includible in this account, shall be recorded in subdivisions separate and distinct from those relating to owned property (Refer to Account 1011004).
5	1010006	Dolet Hills FAS 143 ARO Asset	This account shall include the amount of the FAS 143 ARO assets that are not kept in PowerPlant .
6	1011001	Capital Leases	A. This account shall include the amount recorded under capital leases for plant leased from others and used by the utility in its utility operations. B. The production plant property (steam, nuclear, hydro and other) included in this account shall be classified separately according to the detailed accounts (310 to 346) prescribed for utility plant in service. Effective 7/1/02 - the Account title was changed from "Capital Leases - Production" to "Capital Leases". The business units were unbundled between Generation, Transmission, Distribution, & Nuclear - so the detail was kept by business unit instead of by account.
7	1011004	Capital Leases - Gen & Misc	A. This account shall include the amount recorded under capital leases for plant leased from others and used by the utility in its utility operations. B. The general & miscellaneous property included in this account shall be classified separately according to the detailed accounts (389 to 399) prescribed for general & miscellaneous plant in service.
8	1011006	Prov-Leased Assets	This account shall include the amount recorded under capital leases for accumulated provision for amortization of production plant property (steam, nuclear, hydro and other). Effective 7/1/02 - the Account title was changed from "rov-Leased Assets-Production" to "rov-Leased Assets". The business units were unbundled between Generation, Transmission, Distribution, & Nuclear - so the detail was kept by business unit instead of by account.
9	1050001	Held For Fut Use	This account shall include the original cost of production plant (steam, nuclear, hydro and other), including land and land rights, owned and held for future use in production service under a definite plan for such use, to include: (1) Property acquired, including land and land rights, but never used by the utility in production service, but held for such service in the future under a definite plan, and (2) property, including land and land rights previously used by the utility in service, but retired from such service and held pending its reuse in the future, under a definite plan, in production service. Effective 7/1/02 - the Account title was changed from "Held for Fut Use-Production" to "Held for Fut Use". The business units were unbundled between Generation, Transmission, Distribution, & Nuclear - so the detail is kept by business unit instead of by account.

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
			For Elimination BU's use ONLY no charges should be processed by Non-Elimination BU's (Operating Co's). Process Functional Property Split on Elimination BU's in PeopleSoft. We will split property by Transmission, Distribution & General from current classification of Production on the Elimination BU's.
10	1050003	Held For Fut Use-Distribution	This account shall include the original cost of distribution plant, including land and land rights, owned and held for future use in distribution service under a definite plan for such use, to include: (1) Property acquired, including land and land rights, but never used by the utility in distribution service, but held for such service in the future under a definite plan, and (2) property, including land and land rights previously used by the utility in service, but retired from such service and held pending its reuse in the future, under a definite plan, in distribution service. Previously inactivated 7/1/2002. Reactivated 1/1/2013 and reserved for Elimination companies only, per CF Request # 8678.
11	1060001	Const Not Classifd	This account shall include the total balance of work orders for production plant (steam, nuclear, hydro and other) which have been placed in service but have not been completed and classified for transfer to the detailed electric plant accounts. Effective 7/1/02 - the Account title was changed from "Const Not Classifd-Production" to "Const Not Classifd". The business units were unbundled between Generation, Transmission, Distribution, & Nuclear - so the detail was kept by business unit instead of by account. For Elimination BU's use ONLY no charges should be processed by Non-Elimination BU's (Operating Co's). Process Functional Property Split on Elimination BU's in PeopleSoft. We will split property by Transmission, Distribution & General from current classification of Production on the Elimination BU's.
12	1060002	Const Not Classifd-Transmissn	This account shall include the total balance of work orders for transmission plant which have been placed in service but have not been completed and classified for transfer to the detailed electric plant accounts. Previously inactivated 7/1/2002. Reactivated 1/1/2013 and reserved for Elimination companies only, per CF Request # 8678. For Elimination BU's use ONLY no charges should be processed by Non-Elimination BU's (Operating Co's). Process Functional Property Split on Elimination BU's in PeopleSoft. We will split property by Transmission, Distribution & General from current classification of Production on the Elimination BU's.
13	1060003	Const Not Classifd-Distributio	This account shall include the total balance of work orders for distribution plant which have been placed in service but have not been completed and classified for transfer to the detailed electric plant accounts. Previously inactivated 7/1/2002. Reactivated 1/1/2013 and reserved for Elimination companies only, per CF Request # 8678. For Elimination BU's use ONLY no charges should be processed by Non-Elimination BU's (Operating Co's). Process Functional Property Split on Elimination BU's in PeopleSoft. We will split property by Transmission, Distribution & General from current classification of Production on the Elimination BU's.
14	1060004	Const Not Classifd-Gen&Misc	This account shall include the total balance of work orders for general and miscellaneous plant which have been placed in service but have not been completed and classified for transfer to the detailed electric plant accounts.
15	1070001	CWIP - Project	This account shall include the balance of work orders in process of construction. The functional 1070 balance is maintained by project ID in the PowerPlant Asset Management System. NOTE: Charges to this Balance Sheet account by AEPSC (company number 61) will be passed to the AEPSC Billing System for billing to Client companies.

Southerwestern Electric Power Company **Schedule E-9**
Chart of Accounts
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
16	1080001	A/P for Deprec of Plt	This account shall include the total accumulated provision for depreciation of production plant (steam, nuclear, hydro and other), which will include the provision for depreciation expense, the book cost of the property retired and the cost of removal and salvage related to the asset retired. Effective 7/1/02 - the Account title was changed from "A/P for Deprec of Plt-Productn" to "A/P for Deprec of Plt". The business units were unbundled between Generation, Transmission, Distribution, & Nuclear - so the detail was kept by business unit instead of by account. This account reflects the balance work orders in Retirement Work in Progress. The functional 1080 balance is maintained by project ID in the PowerPlant asset management system.
17	1080005	RWIP - Project Detail	NOTE: Charges to this Balance Sheet account by AEPSC (company number 61) will be passed to the AEPSC Billing System for billing to Client companies.
18	1080011	Cost of Removal Reserve	Cost of Removal Reserve
19	1080012	Dolet Hills FAS 143 ARO Deprec	This account shall include all depreciation amounts for the FAS 143 ARO assets that are not kept in PowerPlant . FIN-47 requires establishing asset retirement obligations for property where our companies have accrued a removal reserve from rate regulated depreciation studies. This account will contain the cumulative effect of implementing the new accounting rule and will have monthly amounts posted representing depreciation and accretion from the ARO assets and liabilities.
20	1080013	ARO Removal Deprec - Accretion	Description change per CF# 7025 effective 1/1/10, was ARO Removal Accretion.
21	1080155	Unrecovered Plant	This account should include the remaining NBV of generating plants/units which have been considered probable for abandonment where companies have been granted the ability to recover the remaining NBV of the plant/unit over the life of another generating facility or unit(s) (i.e. Tanner's Creek Plant in I&M). For FERC reporting, this account should be mapped to Accumulated Provision for Depreciation. For GAAP/SEC reporting, this account should be mapped to Regulatory Assets (similar to FERC account 182.2 Unrecovered Plant).
22	1110001	A/P for Amort of Plt	This account shall include the total accumulated provision for amortization of production plant (steam, nuclear, hydro and other). Effective 7/1/02 - the Account title was changed from "A/P for Amort of Plt-Productio" to "A/P for Amort of Plt". The business units were unbundled between Generation, Transmission, Distribution, & Nuclear - so the detail was kept by business unit instead of by account.
23	1140001	Plant Acquisition Adj	This account is used to track Plant Acquisition Adj
24	1150001	Amrtz of Plt Acqt Adj	This account is used to track Amrtz of Plt Acqt Adj
25	1160007	OthElecPltAdjTurkImprmnt-EPIS	To record activity related to Turk Impairment in EPIS
26	1160008	TurkAFUDCReverseTXCap-EPIS	This account will be used to reverse the AFUDC that is related to the expenditures that are over the Texas jurisdictional cap. This account will need to be mapped to Electric Plant in Service for SEC Reporting
27	1160009	AmortTurkImprmnt&AFUDCReversal	This account will be used for the amortization of Turk Impairment costs and Turk AFUDC reversal until a rate order is received. This account should be mapped to Accumulated Provision for Amortization for reporting purposes
28	1160012	Turk Imprmnt-AuxBoiler	To Record Louisiana exposure related to the Turk Auxilary Boiler per final order in the PUCT Docket No. 40443.
29	1160013	Turk Imprmnt-AuxBoiler Amort	Amortization on the Louisiana exposure related to the Turk Auxilary Boiler per final order in the PUCT Docket No. 40443
30	1160016	TX Trans Veg Mgmt Cost Wrteoff	To record the activity related to the write-off of the Texas portion of capitalized transmission vegetation management costs.
31	1160017	TX Distr Veg Mgmt Cost Wrteoff	To record the activity related to the write-off of the Texas portion of capitalized distribution vegetation management costs.
32	1160018	TX Dist Veg Mgt WriteOff Amort	To record the activity related to the amortization of the write-off of the Texas portion of capitalized distribution vegetation management costs.
33	1160019	TX Tran Veg Mgt WriteOff Amort	To record the amortization of the write-off of the Texas portion of capitalized transmission vegetation management costs.
34	1160020	TX Trans Costs - SERP	Texas portion of the capitalized transmission SERP costs Per Docket# 46449.
35	1160021	TX Distr Costs - SERP	Texas portion of the capitalized distribution SERP costs.
36	1160022	TX Gen Costs - SERP	Texas portion of the capitalized generation SERP costs.
37	1160023	TX CWIP FinBased Incen - Trans	Texas portion of the capitalized financial based incentive costs recorded to CWIP Per Docket# 46449

Southerwestern Electric Power Company **Schedule E-9**
Chart of Accounts
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
38	1160024	TX CWIP FinBased Incen - Distr	Texas portion of the capitalized financial based incentive costs recorded to CWIP Per Docket# 46449.
39	1160025	TX CWIP FinBased Incen - Gen	Texas portion of the capitalized financial based incentive costs recorded to CWIP Per Docket# 46449.
40	1160026	TX RWIP FinBased Incen - Trans	Texas portion of the capitalized financial based incentive costs recorded to RWIP Per Docket# 46449
41	1160027	TX RWIP FinBased Incen - Distr	Texas portion of the capitalized financial based incentive costs recorded to RWIP Per Docket# 46449
42	1160028	TX RWIP FinBased Incen - Gen	Texas portion of the capitalized financial based incentive costs recorded to RWIP Per Docket# 46449
43	1210001	Nonutility Property - Owned	This account shall include the book cost of land, structures, equipment, or other tangible or intangible property owned by the utility, but not used in utility service and not properly includible in account 105, Electric Plant Held for
44	1210003	Nonutility Property - WIP	This account shall include the balance in work orders to acquire tangible or intangible property owned by the utility, but not used in utility service and not properly includible in account 105, Electric Plant Held for Future Use. B. This account shall also include the amount recorded under capital leases for property leased from others and used by the utility in its nonutility operations.
45	1220001	Depr&Amrt of Nonutl Prop-Ownd	This account shall include the accumulated provision for depreciation and amortization applicable to nonutility property owned by the utility in account 1210001.
			This account shall include the accumulated provision for depreciation and amortization applicable to nonutility property in the process of being acquired by the utility.
46	1220003	Depr&Amrt of Nonutl Prop-WIP	This account shall include the total retirement work in progress applicable to nonutility property.
47	1231003	Capital Contributions to Subs	This account shall include the cost of investments in securities issued or assumed by subsidiary companies and investment advances to such companies for capital contributions, including interest accrued thereon when such interest is not subject to current settlement plus the equity in undistributed earnings or losses of such subsidiary companies since acquisition. This account shall be credited with any dividends declared by such subsidiaries.
48	1231005	Invest in Subs Retained Erngs	This account shall include the cost of investments in retained earnings issued or assumed by subsidiary companies and investment advances to such companies, including interest accrued thereon when such interest is not subject to current settlement plus the equity in undistributed earnings or losses of such subsidiary companies since acquisition. This account shall be credited with any dividends declared by such subsidiaries.
49	1231101	Invest Nonconsol Subs-Equity	This account shall include the cost of investments in nonconsolidated subsidiaries equity, including interest accrued thereon when such interest is not subject to current settlement.
50	1231102	Equity in Erngs Nonconsol Subs	This account shall include the equity in earnings in nonconsolidated subsidiaries, including interest accrued thereon when such interest is not subject to current settlement.
51	1240002	Oth Investments-Nonassociated	This account shall include the book cost of investments in securities issued or assumed by nonassociated companies and investment advances to such companies. This account shall also include the offsetting entry to the recording of amortization of discount or premium on interest bearing investments
52	1240027	Other Property - RWIP	This account is used to track Other Property - RWIP
53	1240029	Other Property - CPR	This account is used to track Other Property - CPR
54	1290001	Non-UMWA PRW Funded Position	This account will record the funded position for the Non-UMWA Post Retirement Welfare (PRW) trust as required by FAS 158 guidance.
55	1290002	SFAS 106 - Non-UMWA PRW	This account will record the provisions for Non-UMWA Post Retirement Welfare (PRW) made by the utility and amounts contributed by the Non-UMWA employees for PRW where the funds are include in the assets of the utility.
56	1310000	Cash	This account shall include the amount of current cash funds except working funds.
57	1340018	Spec Deposits - Elect Trading	This account shall include special deposits applicable to electric trading.
58	1340046	Deposits-O&M Dolet Hills Plant	To record deposits paid to Cleco for O&M charges at the Dolet Hills Plant
59	1340048	Spec Deposits-Trading Contra	This account is intended to be used for netting MTM collateral positions in accordance with FIN39-1. Please map to the same balance sheet reporting as account 1340017 and 1340018.
60	1340050	Spec Deposit Mizuho Securities	To record the broker activity related to Mizuho Securities
61	1340051	Spec Depost RBC	To record the broker activity related to RBC Capital Markets.
62	1340053	Deposits - Flexible Spending	This account shall include flexible spending account deposits
63	1420001	Customer A/R - Electric	This account shall include amounts due from customers for electric service.
64	1420006	A/R-Customer Assistance	This account shall include amounts due from customer assistance.
65	1420014	Customer A/R-System Sales	This account shall include amounts due from customers for system sales.
66	1420022	Cust A/R - Factored	This account is used for factoring the AEP-East electric accounts receivable.
67	1420023	Cust A/R-System Sales - MLR	This account shall include amounts due from customers for system sales based on the MLR ratio.
68	1420044	Customer A/R - Estimated	This account shall include the estimated amounts due from customers.

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
69	1420048	Emission Allowance Trading	Account shall be used by Fuel and Contract Accounting to record amounts receivable from nonaffiliated companies solely for allowance trading activities
70	1420051	MISO AR Accrual	This account reflects the net AR/AP accrual with MISO. If the net position is a payable then the balance will be reclassed to the respective payable account. Old account 1430095
71	1420055	SPP AR Accrual	This account reflects the net AR/AP estimate with SPP. Old Account 1840027
72	1420101	Other Accounts Rec - Cust	This account shall include amounts due the utility upon open accounts, other than amounts due from associated companies, and from customers for utility services. This account will be to record amounts due the utility that are customer based receivables. Miscellaneous Recievables (Non-Customer) should be charged to 1430101.
73	1420102	AR Peoplesoft Billing - Cust	This account is used to track A/R PeopleSoft Billing System charges for Customer based transactions.
74	1430002	Allowances	This account shall be used by the Allowance Management System for transactions created by activity at the annual EPA auction of allowances and for the transactions with Buckeye Power for its share of Cardinal Plant allowances. Accounts are assigned to Ledger Accounting for reconciliation.
75	1430022	2001 Employee Biweekly Pay Cnv	This account will be used to record the receivable from the April 12 special pay made in conjunction with the conversion from semi-monthly to bi-weekly pay. The receivable to the company is to be paid back (withheld from employee pay) when employees leave the payroll.
76	1430080	Jointly Owned Unit O&M Billing	This account has been created for the use of the O&M monthly joint billing process. This account shall contain receivables relating to monthly O&M non-associated billing transactions with joint books.
77	1430081	Damage Recovery - Third Party	To record amounts due from third parties for damage to AEP property.
78	1430083	Damage Recovery Offset Demand	To record offset to amounts demanded from third parties for damage to AEP property. This is a contra-asset account for 1430081.
79	1430086	AR Accrual NYMEX OTC Penults	New process to accrue nymex otc and penultimate activity
80	1430101	Other Accounts Rec - Misc	This account shall include amounts due the utility upon open accounts, other than amounts due from associated companies, and from customers for utility services. This account will be to record amounts due the utility that are Miscellaneous (not Customer) based receivables. Customer Other Accounts Recievable should be charged to 1420101.
81	1430102	AR Peoplesoft Billing - Misc	This account is used to track A/R PeopleSoft Billing System charges for Miscellaneous (non customer) based transactions.
82	1430103	AR Long-Term-Miscellaneous	Long Term Accounts Receivable Account for recording miscellaneous (non customer related) receivables which will not be collected within a year.
83	1440002	Uncoll Accts-Other Receivables	This account shall be credited with amounts provided for losses on miscellaneous accounts receivable which may become uncollectible.
84	1460001	A/R Assoc Co - InterUnit G/L	This account includes amounts receivable from affiliated companies derived from interunit General Ledger transactions. This account was previously 1460006. The usage of accounts 1460001 and 1460006 was changed effective 5/1/2000 to facilitate reconciliation of intercompany receivables.
85	1460004	A/R Assoc Co - CM Bills	This account includes amounts receivable from affiliated companies associated with Central Machine Shop and Central Machine Facility billings.
86	1460006	A/R Assoc Co - Intercompany	This account shall include regular drafts upon which associated companies are liable, and which mature and are expected to be paid in full not later than one year from the date of issue, together with any interest thereon, and debit balances subject to current settlement in open accounts with associated companies. Items which do not bear a specified due date but which have been carried for more than twelve months and items which are not paid within twelve months from due date shall be transferred to account 123, Investment in Associated Companies. This account was previously 1460001. The usage of accounts 1460001 and 1460006 was changed effectiuve 5/1/2000 to facilitate reconciliation of intercompany receivables.
87	1460009	A/R Assoc Co - InterUnit A/P	This account includes amounts receivable from affiliated companies derived from interunit Accounts Payable transactions.
88	1460011	A/R Assoc Co - Multi Pmts	This account includes amounts receivable from affiliated companies associated with billings.
89	1460025	Fleet - M4 - A/R	This account shall include accounts receiving from associated companies for M4 transactions.

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
90	1510001	Fuel Stock - Coal	This account shall include the book cost of coal on hand. Items 1. Invoice price of coal less any cash or other discounts. 2. Freight, switching, demurrage and other transportation charges, not including, however, any charges for unloading from the shipping medium. 3. Excise taxes, purchasing agents' commissions, insurance and other expenses directly assignable to cost of coal. 4. Operating, maintenance and depreciation expenses and ad valorem taxes on utility-owned transportation equipment used to transport coal from the point of acquisition to the unloading point. 5. Lease or rental costs of transportation equipment used to transport coal from the point of acquisition to the unloading point.
91	1510002	Fuel Stock - Oil	This account shall include the book cost of oil on hand. Items 1. Invoice price of oil less any cash or other discounts. 2. Freight, switching, demurrage and other transportation charges, not including, however, any charges for unloading from the shipping medium. 3. Excise taxes, purchasing agents' commissions, insurance and other expenses directly assignable to cost of oil. 4. Operating, maintenance and depreciation expenses and ad valorem taxes on utility-owned transportation equipment used to transport oil from the point of acquisition to the unloading point. 5. Lease or rental costs of transportation equipment used to transport oil from the point of acquisition to the unloading point.
92	1510016	Coal Inv on Hand Transp	This account is used to track Coal Inv on Hand Transp
93	1510017	Lignite Inv on Hand Inc Transp	This account is used to track Lignite Inv on Hand Inc Transp
94	1510018	Coal Survey Adjustment	For coal survey adjustments that are to be amortized to coal expense over several months in accordance with State regulations
95	1510020	Fuel Stock Coal - Intransit	Estimated value of coal (including Lignite) which the Company has title to but has not been unloaded at the plant or is otherwise not available for consumption.
96	1520000	Fuel Stock Exp Undistributed	A. This account may include the cost of labor and of supplies used and expenses incurred in unloading fuel from the shipping medium and in the handling thereof prior to its use, if such expenses are sufficiently significant in amount to warrant being treated as a part of the cost of fuel inventory rather than being charged direct to expense as incurred. B. Amounts included herein shall be charged to expense as the fuel is used to the end that the balance herein shall not exceed the expenses attributable to the inventory of fuel on hand. ITEMS Labor: 1. Procuring and handling of fuel. 2. All routine fuel analyses. 3. Unloading from shipping facility and putting in storage. 4. Moving of fuel in storage and transferring from one station to another. 5. Handling from storage or shipping facility to first bunker, hopper, bucket, tank or holder of boiler house structure. 6. Operation of mechanical equipment, such as locomotives, trucks, cars, boats, barges, cranes, etc. Supplies and Expenses: 1. Tools, lubricants and other supplies. 2. Operating supplies for mechanical equipment. 3. Transportation and other expenses in moving fuel. 4. Stores expenses applicable to fuel. This account includes the cost of individual business and professional memberships; see Account 4265004 for social memberships and related expenses and see Account 9302000 for corporate memberships such as for industry dues, e.g., EEI. NOTE: Charges to this Balance Sheet account by AEPSC (company number 61) will be passed to the AEPSC Billing System for billing to Client companies.

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
97	1540001	M&S - Regular	A. This account shall include the cost of materials purchased primarily for use in the utility business for construction, operation and maintenance purposes. It shall also include the book cost of materials recovered in connection with construction, maintenance or the retirement of property, such materials being credited to construction, maintenance or accumulated depreciation provision, respectively, and included herein as follows: (1)Reusable materials consisting of large individual items shall be included in this account at original cost, estimated if not known. The cost of repairing such items shall be charged to the maintenance account appropriate for the previous use; (2) Reusable materials consisting of relatively small items, the identity of which (from the date of original installation to the final abandonment or sale thereof) cannot be ascertained without undue refinement in accounting, shall be included in this account at current prices new for such items. The cost of repairing such items shall be charged to the appropriate expense account as indicated by previous use; (3) Scrap and nonusable materials included in this account shall be carried at the estimated net amount realizable therefrom. The difference between the amounts realized for scrap and nonusable materials sold and the net amount at which the materials were carried in this account, as far as practicable, shall be adjusted to the accounts credited when the materials were charged to this account. B. Materials and supplies issued shall be credited hereto and charged to the appropriate construction, operating expense, or other account on the basis of a unit price determined by the use of cumulative average, first-in-first-out, or such other method of inventory accounting as conforms with accepted accounting standards consistently applied. ITEMS 1. Invoice price of materials less cash or other discounts. 2. Freight, switching or other transportation charges when practicable to include as part of the cost of particular materials to which they relate. 3. Customs duties and excise taxes. 4. Costs of inspection and special tests prior to acceptance. 5. Insurance and other directly assignable charges. Note A: Where expenses applicable to materials purchased cannot be directly assigned to particular purchases, they may be charged to a stores expense clearing account (account 163, Stores Expense Undistributed), and distributed therefrom to the appropriate account. Note B: When materials and supplies are purchased for immediate use, they need not be carried through this account but may be charged directly to the
98	1540004	M&S - Exempt Material	This account shall include the cost of materials purchased primarily for use in the utility business for construction, operation and maintenance purposes that are stored in remote locations instead of the storerooms.
99	1540006	M&S - Lime and Limestone	This account shall include the cost of lime and limestone purchased for use in the utility power plants.
100	1540013	Transportation Inventory	This account shall be used to track Transportation M & S Inventory for Fleet Vehicle Maintenance.
101	1540025	Matls Supply-Activated Carbon	This account shall include the cost of activated carbon purchased for use in some utility power plants.
102	1540028	M&S - Anhydrous Ammonia	This account shall include the cost of anhydrous ammonia purchased for use in utility power plants.
103	1540030	Matls Supply-Calcium Bromide	This account shall include the cost of calcium bromide purchased for use in some utility power plants.
104	1581012	CSAPR An. NOx Inv. - Current	This account should include the cost of CSAPR Annual NOx allowances owned by utility and not withheld by the
105	1581014	CSAPR Seas NOx Comp Inv - Curr	This account should include the cost of Cross State Air Pollution Rule (CSAPR) Seasonal NOx allowances owned by the utility and not withheld by the EPA

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
106	1630004	Strs Exp-T&D Satellite Storerm	A. This account shall include the cost of supervision, labor and expenses incurred in the operation of the transmission and distribution satellite storerooms, including purchasing, storage, handling and distribution of materials and supplies. B. This account shall be cleared by adding to the cost of materials and supplies issued a suitable loading charge which will distribute the expense equitably over stores issues. ITEMS Labor: 1. Inspecting and testing materials and supplies when not assignable to specific items. 2. Unloading from shipping facility and putting in storage. 3. Supervision of purchasing and stores department to extent assignable to materials handled through stores. 4. Getting materials from stock and in readiness to go out. 5. Inventorying stock received or stock on hand by stores employees but not including inventories by general department employees as part of internal or general audits. 6. Purchasing department activities in checking material needs, investigating sources of supply, analyzing prices, preparing and placing orders, and related activities to extent applicable to materials handled through stores. (Optional. Purchasing department expenses may be included in administrative and general expenses.) 7.Maintaining stores equipment. 8. Cleaning and tidying storerooms and stores offices. 9. Keeping stock records, including recording and posting of material receipts and issues and maintaining inventory record of stock. 10. Collecting and handling scrap materials in stores. Supplies and expenses: 1. Adjustments of inventories of materials and supplies but not including large differences which can readily be assigned to important classes of materials and equitably distributed among the accounts to which such classes of materials have been charged since the previous inventory. 2. Cash and other discounts not practically assignable to specific materials. 3. Freight, express, etc., when not assignable to specific items. 4. Heat, light and power for storerooms and store offices. 5. Brooms, brushes, sweeping compounds and other supplies used in cleaning and tidying storerooms and stores offices. 6. Injuries and damages. 7. Insurance on materials and supplies and on stores equipment. 8. Losses due to breakage, leakage, evaporation, fire or other causes, less credits for amounts received from insurance, transportation companies or others in compensation of such losses. 9. Postage, printing, stationery and office supplies. 10. Rent of storage space and facilities. 11. Communication service. 12. Excise and other similar taxes not assignable to specific materials. 13. Transportation expense on inward movement of stores and on transfer between storerooms but not including charges on materials recovered from retirements which shall be accounted for as part of cost of removal. Note: A physical inventory of each class of materials and supplies shall be made at least every two years.
107	1630056	Knox Lee Power Plant	This account shall include the cost of supervision, labor and expenses incurred in the operation of the storeroom, including purchasing, storage, handling and distribution of materials and supplies. B. This account shall be cleared by adding to the cost of materials and supplies issued a suitable loading charge which will distribute the expense equitably over stores issues.
108	1630059	Pirkey Power Plant	This account shall include the cost of supervision, labor and expenses incurred in the operation of the storeroom, including purchasing, storage, handling and distribution of materials and supplies. B. This account shall be cleared by adding to the cost of materials and supplies issued a suitable loading charge which will distribute the expense equitably over stores issues.
109	1630061	Welsh Power Plant	This account shall include the cost of supervision, labor and expenses incurred in the operation of the storeroom, including purchasing, storage, handling and distribution of materials and supplies. B. This account shall be cleared by adding to the cost of materials and supplies issued a suitable loading charge which will distribute the expense equitably over stores issues.
110	1630157	Stores Exp - Mattison Plant	To enable stores accounting to spread storeroom costs to the plant.
111	1650001	Prepaid Insurance	This account shall include amounts representing prepayments of insurance.
112	165000217	Prepaid Taxes	This account shall include amounts representing prepayments of taxes.
113	165000218	Prepaid Taxes	This account shall include amounts representing prepayments of taxes.
114	1650006	Other Prepayments	This account shall include amounts representing prepayments of other items not listed.
115	1650009	Prepaid Carry Cost-Factored AR	This account is used for factoring the AEP-East electric accounts receivable.
116	1650010	Prepaid Pension Benefits	To segregate the west prepaid pension from the other prepaid employee benefits per the request of the reporting group for the purpose of SEC reporting
117	165001117	Prepaid Sales Taxes	This account shall include amounts representing prepayments of sales taxes. Prepayments of Sales vs Use Taxes need to be in separate accounts
118	165001118	Prepaid Sales Taxes	This account shall include amounts representing prepayments of sales taxes. Prepayments of Sales vs Use Taxes need to be in separate accounts
119	165001217	Prepaid Use Taxes	This account shall include amounts representing prepayments of use taxes

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Line No.	G/L Account	Account Description	Additional Description
120	165001218	Prepaid Use Taxes	This account shall include amounts representing prepayments of use taxes
121	165001317	Prepaid Local Franchise Taxes	This account shall include amounts representing prepayments of local franchise taxes.
122	165001318	Prepaid Local Franchise Taxes	This account shall include amounts representing prepayments of local franchise taxes.
123	1650014	FAS 158 Qual Contra Asset	This account is used to track the long term portion of the FAS 158 PBO liability (Projected Benefit Obligation) for the Qualified Pension Plan when the net plan is still prepaid. This account offsets account 1650010.
124	1650017	Prepayment - Coal	Track prepayments required under coal contracts or purchase orders
125	1650021	Prepaid Insurance - EIS	This account shall include amounts representing prepayments of insurance with EIS (Energy Insurance Services).
126	1650023	Prepaid Lease	Track balance of prepaid lease expense for agreements that qualify as a lease under company policy. Prepaid Rents account should be used when the payment does not cover multiple accounting periods or does not qualify as a lease under company policy.
127	1650029	Future Wetlands Credits L-T	This account contains prepayments for wetland mitigation credits that will be required in connection with future mining operations.
128	1650030	Other Prepayments - Long Term	This account shall include amounts representing long term prepayments of other items not listed
129	1650035	PRW Without MED-D Benefits	To record the Prepaid portion of the FAS106 Post Retirement Welfare (PRW) Trust - excluding the effects of the Med-D Subsidy.
130	1650037	FAS158 Contra-PRW Exclud Med-D	To record an offset to the "Post Retirement Welfare (PRW) Without MED-D Benefits" 165 prepaid account for monthly PRW activity. PRW will not report a Prepaid balance for financial reporting, the balance is reported through a 129 account if overfunded or 228 if underfunded.
131	1710048	Interest Receivable -FIT -LT	Interest Receivable -FIT -LT
132	1710348	Interest Receivable -SIT -LT	Interest Receivable -SIT -LT
133	1720000	Rents Receivable	This account shall include rents receivable or accrued on property rented or leased by the utility to others. Note: Rents receivable from associated companies shall be included in account 146, Accounts Receivable from Associated Companies.
134	1730003	Acrd Utility Rev-West	At the option of the utility, the estimated amount accrued for service rendered, but not billed at the end of any accounting period, may be included herein. In case accruals are made for unbilled revenues, they shall be made likewise for unbilled expenses, such as for the purchase of energy specific to the West Companies
135	174001116	Non-Highway Fuel Tax Credit	vintage year account to enable recording of the non-highway fuel tax credit
136	1750001	Curr. Unreal Gains - NonAffil	Amounts recorded in accordance with SFAS 133 as amended, and EITF 02-03, representing current unrealized gains on forward commitments which are not designated as hedges.
137	1750002	Long-Term Unreal Gns - Non Aff	Amounts recorded in accordance with SFAS 133 as amended, and EITF 02-03, representing long-term (greater than one year) unrealized gains on forward commitments which are not designated as hedges.
138	1750021	S/T Asset MTM Collateral	This account is intended to be used for netting MTM collateral positions in accordance with FIN39-1. Please use account number 1750021.
139	1750022	L/T Asset MTM Collateral	This account is intended to be used for netting MTM collateral positions in accordance with FIN39-1. Please use account number 1750022.
140	1810002	Unamort Debt Exp - Inst Pur Cn	This account shall include expenses related to the issuance or assumption of installment purchase contracts. Amounts recorded in this account shall be amortized over the life of each respective issue under a plan which will distribute the amount equitably over the life of the security.
141	1810003	Unamort Debt Exp Notes Payable	This account shall include expenses related to the issuance or assumption of notes payable. Amounts recorded in this account shall be amortized over the life of each respective issue under a plan which will distribute the amount equitably over the life of the security.
142	1810006	Unamort Debt Exp - Sr Unsec Nt	This account shall include expenses related to the issuance or assumption of Senior Unsecured Notes. Amounts recorded in this account shall be amortized over the life of each respective issue under a plan which will distribute the amount equitably over the life of the security.
143	1810102	Unamort Debt Exp-PCB Ins	This account will contain expenses relating to Pollution Control or Installment Purchase Contract Bonds that are not part of the original issuance costs. Example: insurance premiums. These costs will be amortized over the life of the premium.

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Line No.	G/L Account	Account Description	Additional Description
144	1823000	Other Regulatory Assets	A. This account shall include the amounts of regulatory-created assets, not includible in other accounts, resulting from the ratemaking actions of regulatory agencies. (See Definition No. 30.) B. The amounts included in this account are to be established by those charges which would have been included in net income determinations in the current period under the general requirements of the Uniform System of Accounts but for it being probable that such items will be included in a different period(s) for purposes of developing the rates that the utility is authorized to charge for its utility services. When specific identification of the particular source of a regulatory asset cannot be made, such as in plant phase-ins, rate moderation plans, or rate levelization plans, Account 407.4, Regulatory Credits shall be credited. The amounts recorded in this account are generally to be charged, concurrently with the recovery of the amounts in rates, to the same account that would have been charged if included in income when incurred, except all regulatory assets established through the use of Account 407.4 shall be charged to Account 407.3, Regulatory Debits, concurrent with the recovery of the amounts in rates. C. If rate recovery of all or part of an amount included in this account is disallowed, the disallowed amount shall be charged to Account 426.5, Other Deductions, or Account 435, Extraordinary Deductions, in the year of the disallowance.
145	1823010	Energy Efficiency Recovery	This account shall include the amounts of regulatory-created asset applicable to energy efficiency recovery.
146	1823075	Def Exp Selling Price Variance	This account is used to record a regulatory asset resulting from cost under-recovery due to selling price
147	1823077	Unreal Loss on Fwd Commitments	This account shall include the amounts of regulatory-created asset applicable to unrealized loss on forward committments.
148	1823099	Asset Retirement Obligations	New accounting in 2003 for Asset Retirement Obligations will require that expense be recorded at the time of implementation for the cumulative change in accounting principle for non-regulatory obligations. Regulated companies will be permitted to defer the cumulative change in a regulatory asset account. This account will be used to track the regulatory asset amount related to asset retirement obligations.
149	1823108	Reg Asset - Rate Case Expenses	Regulatory Asset for Rate Case Expenses
150	1823149	Unrecovered Fuel Cost - LA	This account shall include the amounts of regulatory created asset applicable to recovered fuel cost as a result of ratemaking actions. Segregation of fuel cost by state jurisdiction for reporting purposes.
151	1823150	Unrecovered Fuel Cost - AR	This account shall include the amounts of regulatory created asset applicable to recovered fuel cost as a result of ratemaking actions. Segregation of fuel cost by state jurisdiction for reporting purposes.
152	1823165	REG ASSET FAS 158 QUAL PLAN	This account is used to track Other Comprehensive Income (OCI) - Minimum Pension Liability, Qualified Pension Plan for regulated business units (SFAS 71).
153	1823166	REG ASSET FAS 158 OPEB PLAN	This account is used to track Other Comprehensive Income (OCI) - Minimum Pension Liability, OPEB (Other Post Employement Benefits) for regulated business units (SFAS 71).
154	1823167	REG Asset FAS 158 SERP Plan	This account is used to track Other Comprehensive Income (OCI) - Minimum Pension Liability, SERP (Supplemental Executive Retirement Plan) for Regulated Busniess Units (SFAS 71).
155	1823219	Under Recovered EAC - LA	Under Recovered Environmental Adjustment Clause (EAC) Rule for Louisiana (LA). The EAC Rule applies to only those pollutants regulated by the United States EPA at the time of Commission adoption, namely, SO2 and NOx. Utilities are required to make a specific request before any other environmental cost for new pollutants can be recovered und the EAC, such as greenhouse gas emission und the Clean Air Act, or any new Federal Legislation.
156	1823241	Valley District Due Diligence	Deferal of Valley District Due Diligence related O&M expenses for five (5) years, with these expenses being included in the rates of SWEPCO pursuant to the terms of an extended FRP or base rate case
157	1823299	SFAS 106 Medicare Subsidy	In 2013, when AEP lost the Medicare Part D subsidy tax benefit, the Company replaced prior year's current retiree prescription drug Medicare Part D subsidy for Medicare-eligible retirees with another government plan known as an Employer Group Waiver Plan (EGWP). As a result, the SFAS 109 asset previously recorded in Account 1823301 is to be transferred to a non-tax related Regulatory Asset for future recovery in AEP's various regulatory jurisdictions.
158	1823301	SFAS 109 Flow Thru Defd FIT	This account has been added for the sole purpose to provide detailed information from the income tax system and interface with the General Ledger. This account shall contain the balance of the regulatory asset related to the SFAS 109 flow through deferred federal income tax.

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Line No.	G/L Account	Account Description	Additional Description
			This account has been added for the sole purpose to provide detailed information from the income tax system and interface with the General Ledger.
159	1823302	SFAS 109 Flow Thru Defrd SIT	This account shall contain the balance of the regulatory asset related to the SFAS 109 flow through deferred state income tax.
160	1823306	Net CCS FEED Study Costs	In June 2011, management approved a billing among AEP operating companies based on megawatt allocation percentages for generating units that could potentially benefit from carbon capture storage (CCS). Management's decision was consistent with requests for recovery of an allocated share of the FEED (Front End Engineering and Design) study costs in VA, OH, and pending applications in MI and IN. This regulatory account will be used to properly classify charges given uncertainty of future construction . Since AEP has postponed the project and we have started requesting recovery of the balance in some of our jurisdictions, we need a regulatory asset account for these Net CCS FEED Study Costs
161	1823324	LA FRP Asset	Regulatory Asset to track receivables due to LPSC orders.
162	1823348	Louisiana Vegetation Managemnt	To Track Louisiana Vegetation Management per LPSC Dkt U-32220.
163	1823359	SWEPCo Transmission Recovery	To Track costs for future recovery of cancelled projects.
164	1823360	2010 Severance Costs	Amortization for Recovery of the 2010 Severance Costs per LPSC 2011 LA FRP Filing
165	1823374	Environmental Chemical Cost-AR	To defer SWEPCo Arkansas Environmental Chemical costs for Pirkey Plant for future recovery per Docket No. 14-080-U.
166	1823377	NBV - AROs Retired Plants	This account shall include the Net Book Value (NBV) of the Asset Retirement Obligations (AROs) which remain after a power plant retires. Any future adjustments to the ARO cashflows of the retiring plants will also be recorded in this account.
167	1823424	LA 2015 FRP Asset-SPP Deferral	To defer the amount of 2017 SPP charges in excess of 2015 SPP charges beginning January 2017, not to exceed $4.5 Million. Amortization to begin in August 2018. Per LPSC STS Docket No. U-34200
168	1823425	LA 2015 FRP Asset - Contra	This new regulatory contra asset account will be used to track the unrecognized equity return for the LA 2015 FRP Asset - SPP Deferral. Per LPSC STS Docket No. U-34200.
169	1823428	Welsh 2 TX Portion Undepr Bal	This account shall include the Texas portion of the undepreciated balance of the retired Welsh Unit 2.
170	1823539	Facilities Maint SWEPCO LA	To track O&M expenses and interest related to the City of Shreveport Sewer Work for future recovery.
171	1823554	WELSH/FLINT CREEK ENVIRONM DEF	This Regulatory Asset will include the deferred Debt and Unrecognized Equity Return, deferred Depreciation Expense, and deferred Property Tax on Welsh and Flint Creek PP Environmental Projects placed in service in 2016. This Reg Asset deferral will continue in accordance with LPSC Docket No. U-34200, pending future recovery.
172	1823555	WELSH/FLINTCREEK ENVIR-CONTRA	This new Regulatory Asset Contra Account (1823) will include the deferred Unrecognized Equity Return on Welsh and Flint Creek Power Plant Environmental Projects placed in service in 2016. This Regulatory Contra Asset will continue in accordance with LPSC Docket No. U-34200, pending future recovery.
173	1830000	Prelimin Surv&Investgtn Chrgs	A. This account shall be charged with all expenditures for preliminary surveys, plans, investigations, etc., made for the purpose of determining the feasibility of utility projects under contemplation. If construction results, this account shall be credited and the appropriate utility plant account charged. If the work is abandoned, the charge shall be made to account 426.5, Other Deductions, or to the appropriate operating expense account. B. This account shall also include costs of studies and analyses mandated by regulatory bodies related to plant in service. If construction results from such studies, this account shall be credited and the appropriate utility plant account charged with an equitable portion of such study costs directly attributable to new construction. The portion of such study costs not attributable to new construction or the entire cost if construction does not result shall be charged to account 182.2, Unrecovered Plant and Regulatory Costs, or the appropriate operating expense account. The costs of such studies relative to plant under construction shall be included directly in account 107, Construction Work in Progress. NOTE: Charges to this Balance Sheet account by AEPSC (company number 61) will be passed to the AEPSC Billing System for billing to Client companies.
174	1840002	Accounts Pay Adj - Clearing	This account shall include undistributed balances in the accounts payable adjustment clearing account at the date of the balance sheet.
175	1840019	CMS & CMF - Clearing Activity	This account shall include undistributed balances in the Central Machine Shop and Central Machine Facilitiy clearing account at the date of the balance sheet.

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176	1840033	Alliance Rail Car - OH	This account shall include undistributed balances in the Alliance Rail Car clearing account at the date of the balance sheet.
177	1840035	IT Oper Company (OPCO) Clearng	This account shall contain Operating Company (OPCO) labor charges relating to IT capital projects.
178	1860001	Allowances	This account shall include amounts applicable to allowances which are in the process of amortization and/or which the proper final disposition is uncertain.
179	1860002	Deferred Expenses	This account shall include amounts applicable to deferred expenses which are in the process of amortization and/or which the proper final disposition is uncertain.
180	186000317	Deferred Property Taxes	This account shall include amounts applicable to deferred property taxes which are in the process of amortization and/or which the proper final disposition is uncertain.
181	186000318	Deferred Property Taxes	This account shall include amounts applicable to deferred property taxes which are in the process of amortization and/or which the proper final disposition is uncertain.
182	1860005	Unidentified Cash Receipts	This account shall include amounts applicable to cashier overages/shortages which are in the process of amortization and/or which the proper final disposition is uncertain.
183	1860007	Billings and Deferred Projects	This accounts includes accumulated costs to be billed to outside parties and deferred costs relating to major
184	1860015	Billings Paid Union Benefits	This account shall include approved labor, coded to timesheet only, by employees who perform approved union roles while an employee of AEP. Amounts to be billed to outside IBEW union parties for represented workers will be charged at cost-plus per negotiated terms, at a frequency no greater than quarterly.
185	1860046	Railroad Cars Subleased	This account shall include amounts applicable to railroad cars subleased which are in the process of amortization and/or which the proper final disposition is uncertain.
186	1860077	Agency Fees - Factored A/R	This account is used for factoring the AEP-East electric accounts receivable.
187	186008117	Defd Property Tax - Cap Lease	This account shall include amounts applicable to deferred property taxes on capital leases which are in the process of amortization and/or which the proper final disposition is uncertain.
188	186008118	Defd Property Tax - Cap Lease	This account shall include amounts applicable to deferred property taxes on capital leases which are in the process of amortization and/or which the proper final disposition is uncertain.
189	1860089	Reclamation Advance	This account will be used to record the carrying amount of reclamation advance for future mining reclamation
190	1860150	Deferred Rate Case Expense	To Capture incremental cost related to deferred rate case expense
191	1860153	Unamortized Credit Line Fees	Account shall be used to capture and amortize the long-term portion of debt issuances costs and commitment fees related to lines of credit. Noncurrent portion of unamortized debt fees.
192	1860156	Sabine Mine Rusk Preparation	Land preparation charges for the Sabine Mine Rusk area to be mined in 2013. After mining begins this account will be amortized based on units of production.
193	1860160	Deferred Expenses - Current	This account shall include amounts applicable to deferred expenses where the proper final disposition is uncertain yet will be resolved in a current period.
194	1860166	Def Lease Assets - Non Taxable	Lease account will be used for holding non taxable leased assets paid for by AEP but yet to be invoiced by new
195	1860171	Marshall South Mine Prep	Land preparation charges for the Sabine Mine Marshall South area to be mined starting in 2014. After mining begins this account will be amortized based on units of production. Charges in this account will be deferred until land is put in service then amortized based on tons mined.
196	1860185	Long Term Assoc AR	To record associated receivables due greater than twelve months.
197	1890001	Loss Recqd Debt - FMB	This account shall include the losses on reacquired or redeemed debt applicable to First Mortage Bonds.
198	1890002	Loss Rec Debt-Ins Purch Cont	This account shall include the losses on reacquired or redeemed debt applicable to installment purchase contracts.
199	1890004	Loss Rec Debt-Debentures	This account shall include the losses on reacquired or redeemed debt applicable to debentures.
200	1900011	ADIT Federal Non-UMWA PRW OCI	This account will be used to record Non-UMWA PRW related accumulated deferred federal income tax related to Other Comprehensive Income (OCI) as required by SFAS 106
201	1900015	ADIT-Fed-Hdg-CF-Int Rate	Deferred Debit regarding "Accumulated Deferred Income Tax - Federal - Hedge - Cash Flow - Interest Rate" recorded in accordance with SFAS 133 "Accounting for Derivative Instruments and Hedging Activities".
202	1901001	Accum Deferred FIT - Other	This account has been added for the sole purpose to provide detailed information from the income tax system and interface with the General Ledger. This account shall contain the balance of accumulated deferred federal income taxes - other.
203	1901002	Accum Deferred SIT - Other	This account has been added for the sole purpose to provide detailed information from the income tax system and interface with the General Ledger. This account shall contain the balance of deferred state income tax.

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			This account has been added for the sole purpose to provide detailed information from the income tax system and interface with the General Ledger.
204	1902001	Accum Defd FIT - Oth Inc & Ded	This account shall contain the balance of accumulated deferred income taxes related to other income and
			This account has been added for the sole purpose to provide detailed information from the income tax system and interface with the General Ledger.
205	1903001	Acc Dfd FIT - FAS109 Flow Thru	This account shall contain the balance of the deferred income tax related to the SFAS 109 flow through.
			This account has been added for the sole purpose to provide detailed information from the income tax system and interface with the General Ledger.
206	1904001	Accum Dfd FIT - FAS 109 Excess	This account shall contain the balance of deferred income tax related to the SFAS 109 excess.
207	2010001	Common Stock Issued-Affiliated	This account shall include the par value or the stated value of stock without par value if such stock has a stated value, and, if not, the cash value of the consideration received for such nonpar stock, of common stock - affiliated actually issued, including the par or stated value of such capital stock in account 124, Other Investments, and account 217, Reacquired Capital Stock.
208	2100000	Gain Rsle/Cancl Req Cap Stock	This account shall include the balance of credits arising from the resale or cancellation of reacquired capital stock.
209	2110000	Miscellaneous Paid-In Capital	This account shall include the balance of all other credits for paid-in capital. This account may include all commissions and expenses incurred in connection with the issuance of capital stock. (In the case of Nonmajor companies, this account shall be kept so as to show the source of the credits includible herein.) ITEMS (NONMAJOR ONLY) 1. Premium received on original issues of capital stock. 2. Donations received from stockholders or reduction of debt of the utility, and the cash value of other assets received as a donation. 3. Reduction in part or stated value of capital stock. 4. Gain on resale or cancellation of reacquired capital stock. Note A: (Major utilities) Amounts included in capital surplus at the effective date of this system of accounts which cannot be classified as to the source thereof shall be included in this account. Note B: (Nonmajor utilities) Premium on capital stock shall not be set off against expenses. Further, a premium received on an issue of a certain class or series of stock shall not be set off against expense of another issue of the same class or series.
210	2160001	Unapprp Retnd Erngs-Unrstrictd	This account shall include the balances, either debit or credit, of unappropriated retained earnings-unrestricted arising from earnings of the utility. This account shall not include any amounts representing the undistributed earnings of subsidiary companies.
211	2161001	Unap Undist Consol Sub Erng	This account shall include the balances, either debit or credit, of unappropriated undistributed retained earnings of subsidiary companies since their acquisition.
212	2161002	Unap Undist Nonconsol Sub Erng	This account shall include the balances, either debit or credit, of unappropriated undistributed retained earnings of nonconsolidated subsidiary companies since their acquisition.
213	2190007	OCI-Min Pen Liab FAS 158-OPEB	This account is used to track Other Comprehensive Income (OCI) - Minimum Pension Liability, OPEB (Other Post Employment Benefits, aka PRW - Post Retirement Welfare).
214	2190015	Accum OCI-Hdg-CF-Int Rate	Other Paid-In Capital regarding "Accumulated Other Comprehensive Income - Hedge - Cash Flow - Interest Rate" recorded in accordance with SFAS 133 "Accounting for Derivative Instruments and Hedging Activities".
215	2240002	Installment Purchase Contracts	This account shall include, until maturity, all long-term debt applicable to installment purchase contracts.
216	2240005	Other Long Term Debt - Other	This account shall include, until maturity, all other long-term debt.
217	2240006	Senior Unsecured Notes	This account shall include, until maturity, all Senior Unsecured Notes
218	2240502	Instl Purchase Contracts-Curr	This account shall include, until maturity, all other long-term debt on installment purchase contracts - current portion.
			This account shall include, until maturity, of all Senior Unsecured Notes-Current
219	2240506	Senior Unsecured Notes-Current	This account was initially establish as an original AIM account. It was inactivated 10/1/99 due to no activity in 1999 Y-T-D and reactivated effective 11/1/99 per KPCo request.
220	2260006	Unam Disc LTD-Dr-Sr Unsec Note	This account shall include the unamortized discount on other Senior Unsecured Notes
221	2270001	Obligatns Undr Cap Lse-Noncurr	This account shall include the portion not due within one year, of the obligations recorded for the amounts applicable to leased property recorded as assets in account 101.1, Property under Capital Leases, account 120.6, Nuclear Fuel under Capital Leases, or account 121, Nonutility Property.
222	2270003	Accrued Noncur Lease Oblig	To record accrued noncurrent lease obligations where leased equipment has been received but AEP has not yet been invoiced by the leasing company.

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			This account shall include amounts reserved to meet the probable liability, not covered by insurance, for deaths or injuries to employees and others and for damages to property neither owned nor held under lease by the utility.
223	2282003	Accm Prv I/D - Worker's Com	The account description was changes from Accm Prov for Injuries&Damages effective 1/1/2000 to reflect this account use only for worker's comp liability.
224	2283000	Accm Prv for Pensions&Benefits	This account shall include provisions made by the utility and amounts contributed by employees for pensions, accident and death benefits, savings, relief, hospital and other provident purposes, where the funds are included in the assets of the utility.
225	2283001	Deferred Compensation Plan	This account shall include provisions made by the utility for pensions, accident and death benefits for deferred compensation purposes, where the funds are included in the assets of the utility.
226	2283002	Supplemental Savings Plan	This account shall include provisions made by the utility and amounts contributed by employees for pensions, accident and death benefits for the supplemental savings plan where the funds are included in the assets of the
227	2283005	SFAS 112 Postemployment Benef	This account shall include provisions made by the utility and amounts contributed by employees for pensions, accident and death benefits for SFAS 112 where the funds are included in the assets of the utility.
228	2283006	SFAS 87 - Pensions	This account shall include provisions made by the utility and amounts contributed by employees for pensions where the funds are included in the assets of the utility.
229	2283007	Perf Share Incentive Plan	This account shall include provisions made by the utility and amounts contributed by employees for performance share incentive plan where the funds are included in the assets of the utility.
230	2283013	Incentive Comp Deferral Plan	This account is used to record incentive award deferrals to the Incentive Compensation Deferral Plan.
231	2283015	FAS 158 SERP Payable Long Term	This account is used to track the long term portion of the FAS 158 PBO liability (Projected Benefit Obligation) for the SERP Plan -Supplemental Executive Retirement Plan.
232	2283016	FAS 158 Qual Payable Long Term	This account is used to track the long term portion of the FAS 158 PBO liability (Projected Benefit Obligation) for the Qualified Pension Plan.
233	2290002	Acc Prv Rate Refnds-Nonassoc	This account shall include accumulated provisions for estimated refunds to nonassociated companies and customers where the utility is collecting amounts in rates subject to refund.
234	2290006	Acc Prv for Potential Refund	Track Accumulative Provision for Potential Refunds
235	2290018	Acc Prov Refunds - Tax Reform	With the passage of the Tax Cuts and Jobs Act of 2017, the AEP regulated subsidiaries will need to defer a portion of their revenues to accommodate the reduction of the corporate tax rate from 35 to 21%. The time frame of the deferral will vary by company as the new tax rate is incorporated into the customer rates over time. The offset will be recorded in 449xxxx.
236	2290019	Acc Prov Refund-Excess Protect	With the passage of the Tax Cuts and Jobs Act, the regulated subsidiaries are required to pass back the protected portion of the excess ADIT, effective 1/2018, in the tax provision system. This account and an associated 229 account will offset/feedback the effect of this tax transaction until the excess is actually returned to the customers.
237	2300001	Asset Retirement Obligations	On October 30, 2002, the FERC issued a Notice of Proposed Rulemaking which detailed new accounts to be used for Asset Retirement Obligations (ARO). FASB Statement 143 requires the Company to adopt new accounting for ARO's in 2003. This account shall contain the liability for those retirement obligations.
238	2300002	ARO - Current	This account shall contain the current liability for FASB Statement 143 asset retirement obligations. FERC Order 631 established Account 230 to be used for Asset Retirement Obligations (ARO).
239	2320001	Accounts Payable - Regular	This account shall include all regular amounts payable by the utility.
240	2320002	Unvouchered Invoices	This account shall include all unvouchered invoices payable by the utility.
241	2320003	Retention	This account shall include all retention payable by the utility.
242	2320008	Miscellaneous Liabilities	To be used for auto-reversing credit balance reclasses from AR accounts.
243	2320011	Uninvoiced Fuel	This account shall include all uninvoiced fuel payable by the utility.
244	2320052	Accounts Payable - Purch Power	This account shall include all accounts payable for physical power and bookouts for utility operations.
245	2320054	Emission Allowance Trading	This account will be used by Fuel and Contract Accounting to record amounts payable to non affiliated companies solely for allowance trading activities.
246	2320062	Broker Fees Payable	This account will be used to record trading activity broker fees payable.
247	2320066	A/P - OPEN ACCESS TRANS EXP	This account is used to track A/P - OPEN ACCESS TRANS EXP
248	2320075	Unvouch - Dolet Hills - Cleco	This account will be used to record all unvouchered O&M Costs for Dolet Hills which is a jointly owned facility by SWEPCO, CLECO, OMPA and NTEC
249	2320076	Corporate Credit Card Liab	Only used for seting up and paying Coporate Credit Card liability
250	2320077	INDUS Unvouchered Liabilities	This account shall include all unvouchered invoices created by INDUS/Passport

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
251	2320089	Mattison-Centerpoint Payable	To record the payable accrual for a firm transportation contract for Mattison plant with Centerpoint. AEP owes Centerpoint $19.1m for 2009 for the construction costs, firm capacity and a commodity fees. Actual gas usage will be paid monthly and any remaining accrual will be paid at the end of the year.
252	2320090	MISO AP Accrual	This account reflects the net AR/AP accrual with MISO. If the net position is a receivable then the balance will be reclassed to the respective receivable account.
253	2330000	Corp Borrow Program (NP-Assoc)	This account shall involve all notes payable to associated companies from the corporate borrowing program with AEP Parent and/or AEP Resources. No manual entries are permitted in this account. Only transactions from PS Treasury. The confirming balance should be in account 1450000.
254	2340001	A/P Assoc Co - InterUnit G/L	This account includes amounts payable to affiliated companies derived from interunit General Ledger transactions. This account was previously 2340027. The usage of accounts 2340001 and 2340027 was changed effective 5/1/2000 to facilitate reconciliation of intercompany receivables.
255	2340025	A/P Assoc Co - CM Bills	This account includes amounts payable to affiliated companies associated with Central Machine Shop billings.
256	2340027	A/P Assoc Co - Intercompany	This account shall include amounts owing to associated companies for intercompany billings and the AEPSC billing. This account was previously 234001. The usage of accounts 2340001 and 2340027 was changed effective 5/1/2000 to facilitate reconciliation of intercompany receivables.
257	2340029	A/P Assoc Co - AEPSC Bills	This account includes amounts payable to AEPSC for the service corporation billing
258	2340030	A/P Assoc Co - InterUnit A/P	This account includes amounts payable to affiliated companies derived from interunit Accounts Payable transactions
259	2340032	A/P Assoc Co - Multi Pmts	This account includes amounts payable to affiliated companies associated with OTC billings.
260	2340033	A/P Assoc Co - Factored A/R	To be determined
261	2340035	Fleet - M4 - A/P	This account is to record interest payable to affiliated companies For Fleet M4.
262	2340041	A/P Assc Co - Non-InterUnit GL	This account is to record Non-InterUnit charges payable to affiliated companies.
263	2350001	Customer Deposits-Active	This account shall include all amounts deposited with the utility by active customers as security for the payment of
264	2350003	Deposits - Trading Activity	This account shall include all amounts deposited with the utility by customers as security for trading activity.
265	2360001	Federal Income Tax	This account shall include the amount of federal income tax accrued.
266	236000209	State Income Taxes	This account shall include the amount of state income tax accrued.
267	236000215	State Income Taxes	This account shall include the amount of state income tax accrued.
268	236000216	State Income Taxes	This account shall include the amount of state income tax accrued.
269	236000217	State Income Taxes	This account shall include the amount of state income tax accrued.
270	236000218	State Income Taxes	This account shall include the amount of state income tax accrued.
271	2360004	FICA	This account shall include the amount of Federal Insurance Contributions Act accrued.
272	2360005	Federal Unemployment Tax	This account shall include the amount of federal unemployment tax accrued.
273	2360006	State Unemployment Tax	This account shall include the amount of state unemployment tax accrued.
274	236000700	State Sales and Use Taxes	This account shall include the amount of state sales and use taxes accrued.
275	236000717	State Sales and Use Taxes	This account shall include the amount of state sales and use taxes accrued.
276	236000718	State Sales and Use Taxes	This account shall include the amount of state sales and use taxes accrued.
277	236000816	Real Personal Property Taxes	This account shall include the amount of real and personal property taxes accrued. NOTE: Tax accruals on capital leased items should be charged to account 2360033 (Real/Pers Prop Tax-Cap Leases) starting in January 2001.
278	236000816	Real Personal Property Taxes	This account shall include the amount of real and personal property taxes accrued. NOTE: Tax accruals on capital leased items should be charged to account 2360033 (Real/Pers Prop Tax-Cap Leases) starting in January 2001.
279	236000817	Real Personal Property Taxes	This account shall include the amount of real and personal property taxes accrued. NOTE: Tax accruals on capital leased items should be charged to account 2360033 (Real/Pers Prop Tax-Cap Leases) starting in January 2001.
280	236000817	Real Personal Property Taxes	This account shall include the amount of real and personal property taxes accrued. NOTE: Tax accruals on capital leased items should be charged to account 2360033 (Real/Pers Prop Tax-Cap Leases) starting in January 2001.

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
281	236000818	Real Personal Property Taxes	This account shall include the amount of real and personal property taxes accrued. NOTE: Tax accruals on capital leased items should be charged to account 2360033 (Real/Pers Prop Tax-Cap Leases) starting in January 2001.
282	236000818	Real Personal Property Taxes	This account shall include the amount of real and personal property taxes accrued. NOTE: Tax accruals on capital leased items should be charged to account 2360033 (Real/Pers Prop Tax-Cap Leases) starting in January 2001.
283	236001216	State Franchise Taxes	This account shall include the amount of state franchise taxes accrued.
284	236001217	State Franchise Taxes	This account shall include the amount of state franchise taxes accrued.
285	236001218	State Franchise Taxes	This account shall include the amount of state franchise taxes accrued.
286	236002016	State Public Service Com Tax	This account shall include the amount of state public service commission tax accrued.
287	236002017	State Public Service Com Tax	This account shall include the amount of state public service commission tax accrued.
288	236002018	State Public Service Com Tax	This account shall include the amount of state public service commission tax accrued.
289	236002216	State License Registration Tax	This account shall include the amount of state license/registration tax accrued.
290	236002217	State License Registration Tax	This account shall include the amount of state license/registration tax accrued.
291	236002517	Local Franchise Tax	This account shall include the amount of local franchise tax accrued.
292	236002518	Local Franchise Tax	This account shall include the amount of local franchise tax accrued.
293	236003317	Pers Prop Tax-Cap Leases	This account shall include the amount of personal property taxes accrued on capital leases.
294	236003317	Pers Prop Tax-Cap Leases	This account shall include the amount of personal property taxes accrued on capital leases.
295	236003318	Pers Prop Tax-Cap Leases	This account shall include the amount of personal property taxes accrued on capital leases.
296	236003318	Pers Prop Tax-Cap Leases	This account shall include the amount of personal property taxes accrued on capital leases.
297	2360037	FICA - Incentive accrual	To accrue FICA applicable to incentive plan payments - employer portion
298	2360501	Fed Inc Tax-Short Term FIN48	New current tax accounts are needed to separate tax positions for FIN 48 purpose - both federal and state
299	2360502	State Inc Tax-Short Term FIN48	New current tax accounts are needed to separate tax positions for FIN 48 purpose - both federal and state. State Income Tax.
300	2360601	Fed Inc Tax-Long Term FIN48	New current tax accounts are needed to separate tax positions for FIN 48 purpose - both federal and state
301	2360602	State Inc Tax-Long Term FIN48	New current tax accounts are needed to separate tax positions for FIN 48 purpose - both federal and state
302	2360701	SEC Accum Defd FIT-Util FIN 48	New FIN 48 Deferred Tax Account to comply with FERC reporting requirements
303	2360702	SEC Accum Defd SIT - FIN 48	New FIN 48 Deferred Tax Account to comply with FERC reporting requirements
304	2360801	Federal Income Tax - IRS Audit	To Record Federal Income Tax as a result of IRS Audit
305	2360901	Accum Defd FIT- IRS Audit	To Record Deferred FIT as a result of IRS Audit
306	2370002	Interest Accrued-Inst Pur Con	This account shall include the amount of interest accrued on installment purchase contracts.
307	2370005	Interest Accrd-Other LT Debt	This account shall include the amount of interest accrued on other long term debt.
308	2370006	Interest Accrd-Sen Unsec Notes	This account shall include the amount of interest accrued on Senior Unsecured Notes.
309	2370007	Interest Accrd-Customer Depsts	This account shall include the amount of interest accrued on customer deposits.
310	2370018	Accrued Margin Interest	Segregate Margin Interest from other type Interest Recorded
311	2370348	Acrd Int. - SIT Reserve - LT	Accrued Interest - State Income Tax Reserve - Long Term
312	2370448	Acrd Int. - SIT Reserve - ST	Accrued Interest - State Income Tax Reserve - Short Term
313	2410002	State Income Tax Withheld	This account shall include the amount of state income taxes withheld by the utility through payroll deductions or otherwise pending transmittal of such taxes to the proper taxing authority.
314	2410003	Local Income Tax Withheld	This account shall include the amount of local income taxes withheld by the utility through payroll deductions or otherwise pending transmittal of such taxes to the proper taxing authority.
315	2410004	State Sales Tax Collected	This account shall include the amount of state sales taxes collected by the utility pending transmittal of such taxes to the proper taxing authority.
316	2410008	Franchise Fee Collected	This account shall include the amount of franchise fee taxes collected by the utility pending transmittal of such taxes to the proper taxing authority.
317	2420000	Misc Current & Accrued Liab	This account shall include the amount of all other miscellaneous current and accrued liabilities.
318	2420002	P/R Ded - Medical Insurance	This account shall include the amount of current and accrued liabilities deducted by payroll deduction for group medical insurance.
319	2420003	P/R Ded - Dental Insurance	This account shall include the amount of current and accrued liabilities deducted by payroll deduction for dental insurance.

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Line No.	G/L Account	Account Description	Additional Description
320	2420010	P/R Ded - Dependent Life Ins	This account shall include the amount of current and accrued liabilities deducted by payroll deduction for dependent life insurance.
321	2420013	P/R Ded - LTD Ins Premiums	This account shall include the amount of current and accrued liabilities deducted by payroll deduction for long term disability insurance premiums.
322	2420016	P/R Ded-Crt Ordr/Grnshmt/Tx Lv	This account shall include the amount of current and accrued liabilities deducted by payroll deduction for garnishees.
323	2420017	P/R Ded - AD&D and OAD&D Ins	This account shall include the amount of current and accrued liabilities deducted by payroll deduction for voluntary accidental death and dismemberment insurance.
324	2420018	P/R Ded-Reg&Spec Life Ins Prem	This account shall include the amount of current and accrued liabilities deducted by payroll deduction for regular and special life insurance premiums.
325	2420020	Vacation Pay - This Year	This account shall include the amount of current and accrued liabilities for vacation pay - this year.
326	2420021	Vacation Pay - Next Year	This account shall include the amount of current and accrued liabilities for vacation pay - next year.
327	2420027	FAS 112 CURRENT LIAB	This account is used to record current portions of FAS 112 liabilities for all related business units.
328	2420046	FAS 158 SERP Payable - Current	This account is used to track the current portion of the FAS 158 PBO liability (Projected Benefit Obligation) for the SERP Plan -Supplemental Executive Retirement Plan.
329	2420051	Non-Productive Payroll	This account shall include the amount of current and accrued liabilities for non-productive payroll.
330	2420053	Perf Share Incentive Plan	This account shall include the amount of current and accrued liabilities for the Performance Share Incentive Plan.
331	2420059	MINE CLOSING COSTS - FERC	This account is used to track MINE CLOSING COSTS - FERC
332	2420071	P/R Ded - Vision Plan	This account shall include the amount of current and accrued liabilities deducted by payroll deduction for the Vision Plan.
333	2420072	P/R - Payroll Adjustment	The account will be used for actual loans to employees for such item as Relocation Loans, related FICA loans, etc
334	2420076	P/R Savings Plan - Incentive	To accrue Savings Plan contributions applicable to incentive plan payments - employer portion
335	2420081	Environmntl Remediation Accrua	This account shall include the liability amount of environmental remediation work and cleanup.
336	2420083	Active Med and Dental IBNR	This account shall be used to record "Incurred but not Reported" liabillity for the active Medical and Dental Plans.
337	2420504	Accrued Lease Expense	This account shall include the amount of accrued liabilities for leases.
338	2420511	Control Cash Disburse Account	This account shall include the amount of current and accrued liabilities for control cash disbursement account.
339	2420512	Unclaimed Funds	This account shall include the amount of current and accrued liabilities for unclaimed funds.
340	2420514	Revenue Refunds Accrued	This account shall include the amount of current and accrued liabilities for revenue refunds accrued.
341	2420532	Adm Liab-Cur-S/Ins-W/C	This account shall include the amount of current and accrued liabilities for admitted liability - current for self-insured workers compensation.
342	242053818	Federal Admin Fee	This account shall include the amount of current and accrued liabilities for federal administration fee.
343	2420558	Admitted Liab NC-Self/Ins-W/C	To separate and classify any non-current admitted liability claims (payouts exceeding one year or more) from current liabilities (payouts less than one year) to be in compliance with SEC regulations.
344	242059217	Sales Use Tax - Leased Equip	This account shall include the amount of current and accrued liabilities for state sales and use tax on leased equipment.
345	242059218	Sales Use Tax - Leased Equip	This account shall include the amount of current and accrued liabilities for state sales and use tax on leased equipment.
346	2420618	Accrued Payroll	This account is used to track Accrued Payroll
347	2420623	Distr, Cust Ops & Reg Svcs ICP	This account is used to record current accruals for the Energy Delivery Incentive Plan
348	2420624	Corp & Shrd Srv Incentive Plan	This account is used to record current accruals for the Corporate & Shared Services Incentive Plan
349	2420635	Generation Incentive Plan	This account is used to record current accruals for the Fossil and Hydro Generation Incentive Plan
350	2420643	Accrued Audit Fees	This account shall include the amount of current and accrued liabilities for external audit fees.
351	2420644	Reclamation Liability - Affil	To accrue FAS 143 reclamation liability that is affiliated
			This account shall include the accrual for the current portion of reclamation liability.
352	2420649	Reclamation Liability - Curr	This account was originally set up for use by AEP Coal and its subsidiaries. It differs from account 2420595 in that it requires a reclamation resource sub-category whereas 2420595 does not.
353	2420660	AEP Transmission ICP	This account is used to record current ICP (Incentive Compensation Plan) accruals for AEP Transmission
354	2420662	Accrued Railcar Lease Exp - ST	To record short-term railcar lease liability transferred from AEP Transportation to I&M and SWEPCO.
355	2420663	Accrued railcar lease exp - LT	To record long-term railcar lease liability transferred from AEP Transportation to I&M and SWEPCO.
356	2420665	Dollar Energy Assistance Pgm	This account is used to track the Dollar Energy customer assistance program collections and payments.
357	2420700	Quality of Service	Record quality of service refunds
358	2430001	Oblig Under Cap Leases - Curr	This account shall include the portion, due within one year, of the obligations recorded for the amounts applicable to capital leases - current.

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Line No.	G/L Account	Account Description	Additional Description
359	2430003	Accrued Cur Lease Oblig	To record accrued current lease obligations where equipment has been received but AEP has not yet been invoiced by the leasing company.
360	2440001	Curr. Unreal Losses - NonAffil	Amounts recorded in accordance with SFAS 133 as amended and EITF 02-03, representing current unrealized losses on forward commitments which are not designated as hedges.
361	2440002	LT Unreal Losses - Non Affil	Amounts recorded in accordance with SFAS 133 as amended and EITF 02-03, representing long-term (greater than one year) unrealized losses on forward commitments which are not designated as hedges.
362	2530000	Other Deferred Credits	This account shall include advance billings and receipts and other deferred credit items, not provided for elsewhere, including amounts which cannot be entirely cleared or disposed of until additional information has been received.
363	2530022	Customer Advance Receipts	This account shall include advance billings and receipts, and other deferred credit items applicable to electric service billed in advance.
364	2530050	Deferred Rev -Pole Attachments	Changed description per chartfield #5911. New: This account shall include advance billings and receipts applicable to pole attachments. Previous title: T.V. Pole Attachments. Previous description: This account shall include advance billings and receipts and other deferred credit items applicable to T.V. pole attachments.
365	2530067	IPP - System Upgrade Credits	This account will be used to book cash that has been paid to AEP to upgrade their transmission sytem which the Independent Power Producer will use when they start using the AEP transmission system. A monthly credit will be subtracted from the participating utility that is using the transmission system.
366	2530101	MACSS Unidentified EDI Cash	This account shall include amounts applicable to unidentified EDI cash which the proper final disposition is
367	2530104	Railroad Cars Subleased-Rev	To record deferred revenues related to subleasing railcars
368	2530112	Other Deferred Credits-Curr	2530xxx account to record other deferred credits that are current in nature according to the SEC balance sheet classification, yet are properly classified in a/c 253 for FERC.
369	2530120	Environ Remediation LT	The purpose of this account is to account for the long term portion of an environmental remediation liability. This will record the portion of the liability that is expected to be paid longer than one year.
370	2530124	Contr In Aid of Constr Advance	To better track property Contribution In Aid of Construction "CIAC" workorders with credit balances.
371	2530181	Oxbow Buy In	To record the portion of Oxbow equipment and/or minerals bought by third parties under contract.
372	2530185	O\U Accounting of ExpensesT	This account will be used to record a liability as a result of monthly over/under accounting of revenues on Transource. Transource can true up its revenues on a monthly basis. As a result, we will record a liability because the LSE's will later be responsible for paying Transource a portion of its revenues once approved by the FERC.
373	2530188	Long Term Assoc AP	To record associated payables due greater than twelve months.
374	2540047	Unreal Gain on Fwd Commitments	This account shall include the amounts of regulatory liabilities imposed by the ratemaking actions of regulatory agencies applicable to unrealized gains on forward committments.
375	2540052	EXCESS EARNINGS	This account will be used to record activity related to EXCESS EARNINGS
376	2540058	Dolet Hills Mining Buy-Out	To segregate the capital cost being bought out by OMPA & NTEC
377	2540090	Over Recovered Fuel Cost - TX	This account shall include the amounts of regulatory created asset applicable to recovered fuel cost as a result of ratemaking actions. Segregation of fuel cost by state jurisdiction for reporting purposes.
378	2540094	Over Recovered Fuel Cost - LA	This account shall include the amounts of regulatory created asset applicable to recovered fuel cost as a result of ratemaking actions. Segregation of fuel cost by state jurisdiction for reporting purposes.
379	2540118	Energy Efficiency O/U Recovery	To capture over recovery costs related to Energy Efficiency program
			To record regulatory liabiility related to billings of cash CWIP through the monthly Louisiana fuel factor for the Turk Power Plant.
380	2540139	Refundable Construction Int-LA	Accounting Implications of the January 13, 2010 Verbal Approval of the November 30, 2009 Proposed Uncontested Stipulated Settlement between Southwestern Electric Power Company and the parties to the Louisiana Public Service Commission Docket No. U-29702
381	2540174	JLStall GR Rider Over Recovery	Record regulated liability for over recovery of the operation and maintenance expenditures, depreciation expense, and carrying costs for the JL Stall Unit 6 at Arsenal Hill, which commenced operation June 16, 2010. The Generaion Recovery (GR) Rider was ordered in Arkansas PSC Docket No. 09-008-U.
382	2540184	Texas Vegetation Management	To record and track Texas Vegetation Mangement per PUCT Docket No. 40443
383	2540191	LA SQIP Veg Mgmt O/U Recovery	To Track the Over/Under Recovery for the SWEPCO Louisiana Vegetation Service Quality Improvement Program (SQIP) per LPSC Docket No. U-32220.

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Line No.	G/L Account	Account Description	Additional Description
			This account has been added for the sole purpose to provide detailed information from the income tax system and interface with the General Ledger.
384	2543001	SFAS109 Flow Thru Def FIT Liab	This account shall contain the balance of the regulatory liability for SFAS 109 flow through deferred federal income taxes. This account has been added for the sole purpose to provide detailed information from the income tax system and interface with the General Ledger.
385	2544001	SFAS 109 Exces Deferred FIT	This account shall contain the balance of the regulatory liability for SFAS 109 excess deferred federal income taxes.
386	2544009	OCI - Excess DFIT	Due to 2018 Tax Reform Act and not to commingle Other Comprehensive Income Deferred Income Tax Liabilities with the Tax Provision System Deferred Income Tax Liabilities. This account number needs mapped to Net Regulatory Assets FAS 109 Reclass Node in PeopleSoft nVision reports.
387	2550001	Accum Deferred ITC - Federal	This account shall be credited with all federal investment tax credits deferred by companies which have elected to follow deferral accounting, partial or full, rather than recognizing in the income statement the total benefits of the tax credit as realized.
388	2570001	Unamort Gn Reacq Debt - FMB	This account shall include the amounts of unamortized gain on reacquired debt - First Mortgage Bonds. This account has been added for the sole purpose to provide detailed information from the income tax system and interface with the General Ledger.
389	2811001	Acc Dfd FIT - Accel Amort Prop	This account shall contain the balance of theaccumulated deferred federal income tax for accelerated amortization property. This account has been added for the sole purpose to provide detailed information from the income tax system and interface with the General Ledger.
390	2814001	Acc Dfd FIT - FAS 109 Excess	This account shall contain the balance of the accumualted deferred federal income tax related to the SFAS 109 excess. This account has been added for the sole purpose to provide detailed information from the income tax system and interface with the General Ledger.
391	2821001	Accum Defd FIT - Utility Prop	This account shall contain the balance of accumulated deferred federal income tax related to utility property. This account has been added for the sole purpose to provide detailed information from the income tax system and interface with the General Ledger.
392	2823001	Acc Dfrd FIT FAS 109 Flow Thru	This account shall contain the balance of accumulated deferred federal income taxes related to the SFAS 109 flow through. This account has been added for the sole purpose to provide detailed information from the income tax system and interface with the General Ledger.
393	2824001	Acc Dfrd FIT - SFAS 109 Excess	This account shall contain the balance of accumulated deferred federal income taxes related to the SFAS 109 This account has been added for the sole purpose to provide detailed information from the income tax system and interface with the General Ledger.
394	2831001	Accum Deferred FIT - Other	This account shall contain the balance of accumulated deferred federal income taxes - other. This account has been added for the sole purpose to provide detailed information from the income tax system and interface with the General Ledger.
395	2831002	Accum Deferred SIT - Other	This account shall contain the balance of accumulated deferred state income taxes - other. This account has been added for the sole purpose to provide detailed information from the income tax system and interface with the General Ledger.
396	2832001	Accum Dfrd FIT - Oth Inc & Ded	This account shall contain the balance of accumulated deferred federal income taxes related to other income and deductions.

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Line No.	G/L Account	Account Description	Additional Description
			This account has been added for the sole purpose to provide detailed information from the income tax system and interface with the General Ledger.
397	2833001	Acc Dfd FIT FAS 109 Flow Thru	This account shall contain the balance of accumulated deferred federal income taxes related to the SFAS 109 flow through.
			This account has been added for the sole purpose to provide detailed information from the income tax system and interface with the General Ledger.
398	2833002	Acc Dfrd SIT FAS 109 Flow Thru	This account shall contain the balance of accumulated deferred state income taxes related to SFAS 109 flow
			This account has been added for the sole purpose to provide detailed information from the income tax system and interface with the General Ledger.
399	2834001	Acc Defd FIT - SFAS 109 Excess	This account shall contain the balance of accumulated deferred federal income taxes related to the SFAS 109
400	4010001	Operation Exp - Nonassociated	This account shall include the total amount included in the utility operation expense accounts from nonassociated companies.
			This account shall include the amount of depreciation expense for all classes of depreciable production plant in service.
401	4030001	Depreciation Exp	Effective 7/1/02 - the Account title was changed from "Depreciation Exp - Production" to "Depreciation Exp". The business units were unbundled between Generation, Transmission, Distribution, & Nuclear - so the detail was kept by business unit instead of by account.
			This account will include Deferred Depreciation Expense relating to Capital Projects that are pending future recovery. This account may also include amortization of previously deferrred Depreciation Expense that has been approved for recovery.
402	4030028	Depreciation Expense Deferred	
403	4031001	Depr - Asset Retirement Oblig	To record depreciation expense on Asset Retirement Obligations.
404	4037000	Amort-TX Cap Impairment	To amortize TX Cap Impairment costs related to Turk Plant
405	4037001	Amort TX SERP	Amortization of theTexas portion of SERP Costs Per Docket# 46449
406	4037002	Amort TX RWIP Cap Incen	Amortization of theTexas portion of the capitalized financial based incentive costs recorded to RWIP Per Docket# 46449
407	4037003	Amort TX CWIP Cap Incent	Amortization of theTexas portion of the capitalized financial based incentive costs recorded to CWIP Per Docket# 46449
408	4037004	Amort TX Cap Veg Mgmt Costs	To record the amortization of Texas capitalized vegetation management costs.
			This account shall include amortization charges applicable to amounts included in the production plant accounts.
409	4040001	Amort. of Plant	Effective 7/1/02 - the Account title was changed from "Amort. of Plant - Production" to "Amort. of Plant". The business units were unbundled between Generation, Transmission, Distribution, & Nuclear - so the detail was kept by business unit instead of by account.
410	4073000	Regulatory Debits	This account shall include amounts recorded as a result of regulatory liabilities imposed on the utility by the ratemaking actions of regulatory agencies applicable to utility plant.
411	4073016	Welsh Unit 2 Reg Asset Amort	To record the amortization of the regulatory asset for the Texas poriton of the undepreciated balance of the retired Welsh Unit 2.
412	4073017	Welsh U2 ARO Reg Asset Amort	To record the amortization of the Texas portion of the ARO regulatory asset for the retired Welsh Unit 2.
413	4074000	Regulatory Credits	This account is used to track Regulatory Credits
414	4081002	FICA	This account shall include Federal Insurance Contributions Act taxes relating to utility operating income.
415	4081003	Federal Unemployment Tax	This account shall include Federal Unemployment Taxes relating to utility operating income.
416	408100514	Real Personal Property Taxes	This account shall include real and personal property taxes relating to utility operating income.
417	408100515	Real Personal Property Taxes	This account shall include real and personal property taxes relating to utility operating income.
418	408100516	Real Personal Property Taxes	This account shall include real and personal property taxes relating to utility operating income.
419	408100517	Real Personal Property Taxes	This account shall include real and personal property taxes relating to utility operating income.
420	408100518	Real Personal Property Taxes	This account shall include real and personal property taxes relating to utility operating income.
421	408100614	State Gross Receipts Tax	This account shall include State gross receipts/revenue/income taxes relating to utility operating income.
422	408100615	State Gross Receipts Tax	This account shall include State gross receipts/revenue/income taxes relating to utility operating income.

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
423	408100616	State Gross Receipts Tax	This account shall include State gross receipts/revenue/income taxes relating to utility operating income.
424	408100617	State Gross Receipts Tax	This account shall include State gross receipts/revenue/income taxes relating to utility operating income.
425	408100618	State Gross Receipts Tax	This account shall include State gross receipts/revenue/income taxes relating to utility operating income.
426	4081007	State Unemployment Tax	This account shall include State unemployment taxes relating to utility operating income.
427	408100815	State Franchise Taxes	This account shall include State franchise taxes relating to utility operating income.
428	408100816	State Franchise Taxes	This account shall include State franchise taxes relating to utility operating income.
429	408100817	State Franchise Taxes	This account shall include State franchise taxes relating to utility operating income.
430	408100818	State Franchise Taxes	This account shall include State franchise taxes relating to utility operating income.
431	408101414	Federal Excise Taxes	This account shall include Federal excise taxes relating to utility operating income.
432	408101415	Federal Excise Taxes	This account shall include Federal excise taxes relating to utility operating income.
433	408101416	Federal Excise Taxes	This account shall include Federal excise taxes relating to utility operating income.
434	408101417	Federal Excise Taxes	This account shall include Federal excise taxes relating to utility operating income.
435	408101418	Federal Excise Taxes	This account shall include Federal excise taxes relating to utility operating income.
436	408101715	St Lic-Rgstrtion Tax-Fees	This account shall include State license/registration tax/fees relating to utility operating income.
437	408101716	St Lic-Rgstrtion Tax-Fees	This account shall include State license/registration tax/fees relating to utility operating income.
438	408101717	St Lic-Rgstrtion Tax-Fees	This account shall include State license/registration tax/fees relating to utility operating income.
439	408101718	St Lic-Rgstrtion Tax-Fees	This account shall include State license/registration tax/fees relating to utility operating income.
440	408101814	St Publ Serv Comm Tax-Fees	This account shall include State Public Service Commision tax/fees relating to utility operating income.
441	408101815	St Publ Serv Comm Tax-Fees	This account shall include State Public Service Commision tax/fees relating to utility operating income.
442	408101816	St Publ Serv Comm Tax-Fees	This account shall include State Public Service Commision tax/fees relating to utility operating income.
443	408101817	St Publ Serv Comm Tax-Fees	This account shall include State Public Service Commision tax/fees relating to utility operating income.
444	408101818	St Publ Serv Comm Tax-Fees	This account shall include State Public Service Commision tax/fees relating to utility operating income.
445	408101900	State Sales and Use Taxes	This account is used to track State Sales and Use Taxes
446	408101914	State Sales and Use Taxes	This account shall include State sales and use taxes relating to utility operating income.
447	408101915	State Sales and Use Taxes	This account shall include State sales and use taxes relating to utility operating income.
448	408101916	State Sales and Use Taxes	This account shall include State sales and use taxes relating to utility operating income.
449	408101917	State Sales and Use Taxes	This account shall include State sales and use taxes relating to utility operating income.
450	408101918	State Sales and Use Taxes	This account shall include State sales and use taxes relating to utility operating income.
451	408102215	Municipal License Fees	This account shall include Municipal license taxes relating to utility operating income.
452	408102216	Municipal License Fees	This account shall include Municipal license taxes relating to utility operating income.
453	408102217	Municipal License Fees	This account shall include Municipal license taxes relating to utility operating income.
454	408102218	Municipal License Fees	This account shall include Municipal license taxes relating to utility operating income.
455	408102315	Local Privilege-Franchise Tax	This account shall include local privilege/franchise taxes relating to utility operating income.
456	408102316	Local Privilege-Franchise Tax	This account shall include local privilege/franchise taxes relating to utility operating income.
457	408102317	Local Privilege-Franchise Tax	This account shall include local privilege/franchise taxes relating to utility operating income.
458	408102318	Local Privilege-Franchise Tax	This account shall include local privilege/franchise taxes relating to utility operating income.
459	408102716	Misc State and Local Taxes	This account should be used to record the expense of miscellaneous state and local taxes.
460	408102914	Real-Pers Prop Tax-Cap Leases	This account will be used to record activity related to Real/Pers Prop Tax-Cap Leases
461	408102915	Real-Pers Prop Tax-Cap Leases	This account will be used to record activity related to Real/Pers Prop Tax-Cap Leases
462	408102916	Real-Pers Prop Tax-Cap Leases	This account will be used to record activity related to Real/Pers Prop Tax-Cap Leases
463	408102917	Real-Pers Prop Tax-Cap Leases	This account will be used to record activity related to Real/Pers Prop Tax-Cap Leases
464	408102918	Real-Pers Prop Tax-Cap Leases	This account will be used to record activity related to Real/Pers Prop Tax-Cap Leases
465	4081033	Fringe Benefit Loading - FICA	This account carries the credits to FICA tax for the fringe benefit loading for Capital and Balance Sheet accounts
466	4081034	Fringe Benefit Loading - FUT	This account carries the credits to FUT for the fringe benefit loading for Capital and Balance sheet accounts
467	4081035	Fringe Benefit Loading - SUT	This account carries the credits to SUT for the fringe benefit loading for Capital and Balance Sheet accounts
468	408103614	Real Prop Tax-Cap Leases	In 2002 Real and Personal Property Tax Accruals for Leased Assets were seperated into two accounts, 2360033 was for personal and 2360035 was for real, however the contra account was not seperated between personal and real, account 4081029 was being used for both personal and real. This account will be used solely for the real property taxes while 4081029 will be used solely for personal property.
469	408200514	Real Personal Property Taxes	This account shall include real and personal property taxes relating to other income and deductions.
470	408200516	Real Personal Property Taxes	This account shall include real and personal property taxes relating to other income and deductions.
471	408200517	Real Personal Property Taxes	This account shall include real and personal property taxes relating to other income and deductions.
472	4091001	Income Taxes, UOI - Federal	This account shall include Federal income taxes relating to utility operating income.

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
473	409100209	Income Taxes, UOI - State	This account shall include State income taxes relating to utility operating income.
474	409100215	Income Taxes UOI - State	This account shall include State income taxes relating to utility operating income.
475	409100216	Income Taxes UOI - State	This account shall include State income taxes relating to utility operating income.
476	409100217	Income Taxes UOI - State	This account shall include State income taxes relating to utility operating income.
477	409100218	Income Taxes UOI - State	This account shall include State income taxes relating to utility operating income.
478	4092001	Inc Tax, Oth Inc&Ded-Federal	This account shall include Federal income taxes relating to other income and deductions.
479	409200215	Inc Tax Oth Inc Ded - State	This account shall include State income taxes relating to other income and deductions.
480	409200216	Inc Tax Oth Inc Ded - State	This account shall include State income taxes relating to other income and deductions.
481	409200217	Inc Tax Oth Inc Ded - State	This account shall include State income taxes relating to other income and deductions.
482	409200218	Inc Tax Oth Inc Ded - State	This account shall include State income taxes relating to other income and deductions.
483	4101001	Prov Def I/T Util Op Inc-Fed	This account shall include the amounts of deferred Federal income tax relating to utility operating income.
			This account shall include the amounts of deferred State income tax relating to utility operating income.
484	4101002	Prov Def I/T Util Op Inc-State	Account reactivated 3/1/01 per Tax Dept. request.
485	4102001	Prov Def I/T Oth I&D - Federal	This account shall include the amounts of deferred Federal income taxes which relate to other income and
486	4111001	Prv Def I/T-Cr Util Op Inc-Fed	This account shall include the amounts of deferred Federal income taxes, credit, which relate to utility operating income.
487	4111002	Prv Def I/T-Cr UtilOpInc-State	This account shall include the amounts of deferred State income taxes, credit, which relate to utility operating
488	4111005	Accretion Expense	On October 30, 2002, the FERC issued a Notice of Proposed Rulemaking which detailed new accounts to be used for Asset Retirement Obligations (ARO). FASB Statement 143 requires the Company to adopt the new accounting for ARO's in 2003.
489	4112001	Prv Def I/T-Cr Oth I&D-Fed	This account will be used to record activity related to Prv Def I/T-Cr Oth I&D-Fed
490	4114001	ITC Adj, Utility Oper - Fed	This account shall include the amount of Federal investment tax credit adjustments related to property used in utility operations.
491	4116000	Gain From Disposition of Plant	This account shall include, as approved by FERC, amounts relating to gains from the disposition of future use utility plant.
492	4118002	Comp. Allow Gains Title IV SO2	This account shall be credited with the gain on the sale, exchange, or other disposition of compliance allowances.
493	4118006	CSAPR SO2 Gains	To track gains on new compliance CSAPR allowances
494	4118008	Comp Allow Gain CSAPR Seas NOx	This account shal be credited with the gain on the sale, exchange, or other disposition of compliance Cross State Air Pollution Rule (CSAPR) seasonal NOx allowances
495	4118009	Comp Allow Gains CSAPR An NOx	This account shall be credited with the gain on the sale, exchange, or other disposition of compliance Cross State Air Pollution Rule CSAPR) annual NOx allowances
496	4180001	Non-Operatng Rental Income	This account shall include all non-operating rental revenues and related expenses from land, buildings, or other property included in Account 1210000.
			This account shall include all non-operating rental revenues and related expenses from the maintenance of land, buildings, or other property included in Account 1210000.
497	4180003	Non-Opratng Rntal Inc-Maint	State jurisdiction was removed in February 2003 business at the request of Regulated Accounting and the approval of the Tax Department.
498	4181001	Equity Erngs of Sub-Consolidat	This account shall include the utility's equity in the earnings of subsidiary companies - consolidated.
499	4181002	Equity Erngs of Sub-Nonconsol	This account shall include the utility's equity in the earnings of subsidiary companies - nonconsolidated.
500	4190002	Int & Dividend Inc - Nonassoc	This account shall include interest revenues on securities, loans, notes, advances, special deposits, tax refunds and all other interest-bearing assets applicable to nonassociated companies, and dividends on stocks of other nonassociated companies, whether the securities on which the interest and dividends are received are carried as investments or included in sinking or other special fund accounts
501	4190005	Interest Income - Assoc CBP	This account shall include interest revenues on securities, loans, notes, advances, special deposits, tax refunds and all other interest-bearing assets applicable to associated companies, whether the securities on which the interest are received are carried as investments or included in sinking or other special fund accounts within the Corporate Borrowing Program. No manual entries are permitted in this account.
502	4191000	Allw Oth Fnds Usd Drng Cnstr	This account shall include concurrent credits for allowance for other funds used during construction.
503	4210002	Misc Non-Op Inc-NonAsc-Rents	This account shall include all miscellaneous non-operating revenue items except taxes applicable to non-associated rents.

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
504	4210003	Misc Non-Op Inc-NonAscRoylty	This account shall include all miscellaneous non-operating revenue items except taxes applicable to non-associated royalties.
505	4210005	Misc Non-Op Inc-NonAsc-Timber	This account shall include all miscellaneous non-operating revenue items except taxes applicable to non-associated timber.
506	4210007	Misc Non-Op Inc - NonAsc - Oth	This account shall include all miscellaneous non-operating revenue items except taxes applicable to non-associated other.
507	4210009	Misc Non-Op Exp - NonAssoc	This account shall include all miscellaneous non-operating expense items except taxes applicable to non-associated companies.
508	4211000	Gain on Dspsition of Property	This account shall include the gain on the sale, conveyance, exchange, or transfer of utility or other property.
509	4212000	Loss on Dspsition of Property	This account shall include the loss on the sale, conveyance, exchange, or transfer of utility or other property.
510	4261000	Donations	This account shall include all payments or donations for charitable, social or community welfare purposes.
511	4261002	Donations - Nontaxable	To set new 426.1 account to split nontax deductible donations from taxable ones as requested by the tax
512	4263001	Penalties	This account shall include payments by the company for penalties or fines for violation of any regulatory statutes by the company or its officials.
513	4263003	Penalties - Quality of Service	This account shall include payments by the company for Tax Deductible penalties in violation of state Quality of Service Standards.
514	4264000	Civic and Political Activity	This account shall include expenditures for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances (either with respect to the possible adoption of new referenda, legislation or ordinances or repeal or modification of existing referenda, legislation or ordinances) or approval, modification, or revocation of franchises or for the purpose of influencing the decisions of public officials, but shall not include such expenditures which are directly related to appearances before regulatory or other governmental bodies in connection with the reporting utility's existing or proposed operations.
515	4264001	Non-deduct Lobbying per IRS	To separately track and identify lobbying expenses that are not deductible for tax purposes in accordance with the Internal Revenue Code
516	4265002	Other Deductions - Nonassoc	This account shall include miscellaneous expenses applicable to non-associated companies which are properly deductible before determining total income before interest charges.
517	4265004	Social & Service Club Dues	This account includes the cost of social memberships and related expenses; see Account 9302000 for corporate memberships and see various miscellaneous functional accounts for individual business and professional memberships. (Prior description: This account shall include miscellaneous expenses applicable to social and service club dues which are properly deductible before determining total income before interest charges.)
518	4265007	Regulatory Expenses	This account shall include miscellaneous expenses applicable to regulatory expenses which are properly deductible before determining total income before interest charges.
519	4265009	Factored Cust A/R Exp - Affil	This account shall include expenses associated with factoring customers' accounts receivable, excluding amounts related to charged off accounts. Specifically, this account shall include expenses for carrying costs and credit line fees charged by AEP Credit, an affiliated company.
520	4265010	Fact Cust A/R-Bad Debts-Affil	This account shall include expenses associated with factored accounts receivable uncollectible accounts expense charged by AEP Credit, an affiliated company.
521	4265033	Transition Costs	Transition costs include charges: (1) to modify operational, financial, tax and accounting processes and reports, (2) to modify integrated systems (e.g. feeder systems), (3) to transfer employees, (4) to revise controls, etc. Transition cost represent costs that would not be incurred but for the directive and should be recorded below the line so there is no recovery of the costs. All internal labor costs associated with these projects should be charged to this account.
522	4265038	Wind Catcher Project Expenses	This account will be used to expense all costs related to the Wind Catcher Project excluding AFUDC.
523	4270002	Int on LTD - Install Pur Contr	This account shall include the amount of interest on long-term debt issued or assumed by the utility on installment purchase contracts.
524	4270005	Int on LTD - Other LTD	This account shall include the amount of interest on long-term debt issued or assumed by the utility on other long-term debt.
525	4270006	Int on LTD - Sen Unsec Notes	This account shall include the amount of interest on long-term debt issued or assumed by the utility for senior unsecured notes.
526	4280002	Amrtz Debt Dscnt&Exp-Instl Pur	This account shall include the amount of amortized debt discount and expense on outstanding long-term debt applicable to installment purchase contracts.

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
527	4280003	Amrtz Debt Dscnt&Exp-N/P	This account shall include the amount of amortized debt discount and expense on outstanding long-term debt applicable to notes payable.
528	4280006	Amrtz Dscnt&Exp-Sn Unsec Note	This account shall include the amount of amortized debt discount and expense on outstanding long-term debt applicable to senior unsecured notes.
529	4281001	Amrtz Loss Rcquired Debt-FMB	This account shall include the amount of amortized losses on reacquired debt applicable to First Mortgage Bonds.
530	4281002	Amrtz LossRcquired Debt-IPC	This account shall include the amount of amortized losses on reacquired debt applicable to installment purchase contracts.
531	4281004	Amrtz Loss Rcquired Debt-Dbnt	This account shall include the amount of amortized losses on reacquired debt applicable to debentures.
532	4291001	Amrtz Gain Rcqred Debt-Cr-FMB	This account shall include the amount of amortized gains realized from reacquired debt - credit - applicable to First Mortgage Bonds.
533	4300003	Int to Assoc Co - CBP	This account shall include interest associated companies associated with corporate borrowing program transactions.
534	4310001	Other Interest Expense	This account shall include all interest expense not provided for elsewhere.
535	4310002	Interest on Customer Deposits	This account shall include all interest expense on customer deposits.
536	4310007	Lines Of Credit	This account shall include other interest expense on short-term debt applicable to fees on lines of credit.
537	4310014	OTHER INTEREST - FUEL RECOVERY	This account is used to track OTHER INTEREST - FUEL RECOVERY
538	4310017	Mine Reclamation Interest	This account shall be used to record interest expense accrued in anticipation of the land reclamation associated with the closing of coal mines
539	4310023	Interest Expense - State Tax	Separate Tax Interest from all other Interest to facilitate closing and reporting of tax interest
540	4320000	Allw Brrwed Fnds Used Cnstr-Cr	This account shall include concurrent credits for allowance for borrowed funds used during construction - credit.
541	4380001	Div Declrd - Common Stk - Asso	This account shall include amounts declared payable out of retained earnings as dividends on actually outstanding common capital stock issued by the utility applicable to associated companies.
542	4380001	Div Declrd - Common Stk - Asso	This account shall include amounts declared payable out of retained earnings as dividends on actually outstanding common capital stock issued by the utility applicable to associated companies.
543	4390000	Adj to Retained Earnings	This account shall, with prior Commission approval, include significant nonrecurring transactions accounted for as prior period adjustments, as follows: (1)Correction of an error in the financial statements of a prior year. (2)Adjustments that result from realization of income tax benefits of pre-acquisition operating loss carryforwards of purchased subsidiaries. All other items of profit and loss recognized during a year shall be included in the determination of net income for that year
544	4400001	Residential Sales-W/Space Htg	This account shall include the net billing for electricity supplied for residential or domestic purposes with space
545	4400002	Residential Sales-W/O Space Ht	This account shall include the net billing for electricity supplied for residential or domestic purposes without space heating.
546	4400005	Residential Fuel Rev	This account is used to track Residential Fuel Rev
547	4400006	Residential O/U Fuel Rev	This account is used to track Residential O/U Fuel Rev
548	4420001	Commercial Sales	This account shall include the net billing for electricity supplied to customers for commercial purposes.
549	4420002	Industrial Sales (Excl Mines)	This account shall include the net billing for electricity supplied to customers for industrial purposes excluding mine power.
550	4420006	Sales to Pub Auth - Schools	This account shall include the net billing for electricity supplied to customers for commercial and industrial purposes - Public Authorities - including schools.
551	4420007	Sales to Pub Auth - Ex Schools	This account shall include the net billing for electricity supplied to customers for commercial and industrial purposes - Public Authorities - excluding schools.
552	4420013	Commercial Fuel Rev	This account is used to track Commercial Fuel Rev
553	4420014	Commercial O/U Fuel Rev	This account is used to track Commercial O/U Fuel Rev
554	4420016	Industrial Fuel Rev	This account is used to track Industrial Fuel Rev
555	4420017	Industrial O/U Fuel Rev	This account is used to track Industrial O/U Fuel Rev
556	4440000	Public Street/Highway Lighting	This account shall include the net billing for electricity supplied and services rendered for the purposes of lighting streets, highways, parks and other public places, or for traffic or other signal system service, for municipalities or other divisions or agencies of state or federal governments
557	4440002	Public St & Hwy Light Fuel Rev	This account is used to track Public St & Hwy Light Fuel Rev
558	4440003	Pb St & Hwy Light O/U Fuel Rev	This account is used to track Pb St & Hwy Light O/U Fuel Rev
559	4470001	Sales for Resale - Assoc Cos	This account shall include the net billing for electricity supplied to associated companies.
560	4470002	Sales for Resale - NonAssoc	This account shall include the net billing for electricity supplied to non-associated companies.
561	4470006	Sales for Resale-Bookout Sales	This account shall include the net billing for electricity supplied for sales for resale for non-associated companies - bookouts.

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
			This account shall include revenues for sales for resale - bookout purchases.
562	4470010	Sales for Resale-Bookout Purch	This account was inactivated effective 5/1/2001 as a result of the change from the net to gross method for recording bookout purchases. The replacement account is 5550012 (Purchased Power - Bookouts).
563	4470027	Whsal/Muni/Pb Ath Fuel Rev	This account is used to track Sale/Resal - Whsal/Muni/Pb Ath
564	4470028	Sale/Resale - NA - Fuel Rev	This account is used to track Sale/Resale - NA - Fuel Rev
565	4470032	Capacity Revenue - Affiliated	To record the capacity revenue received from affiliated companies.
566	4470033	Whsal/Muni/Pub Auth Base Rev	To record base revenues from wholesale customers, municipal customers and public authorities.
567	4470035	Sls for Rsl - Fuel Rev - Assoc	To record the fuel revenue for sales for resale to associated companies
568	4470036	Sales for Resale- Fuel - ERCOT	This account will be used to record activity related to Sales for Resale- Fuel - ERCOT
569	4470081	Financial Spark Gas - Realized	This account shall include the net billings of settled spark gas financial transactions
570	4470082	Financial Electric Realized	This account shall include settled financial electric optimization transactions (Swaps and Futures) entered into on or after 10-01-03
571	4470131	Non-Trading Bookout Purch-OSS	Description change per CF#7064 effective 2/1/10. To record purchased power for non-trading off-system sales (OSS) - Bookouts.
572	4470136	SPP Rev Neutrality Ded-Sales	To record SPP Dedicated Revenue Neutrality sales in a separate 447xxxx account.
573	4470142	SPP Resource Imb Ded-Sales	To record SPP Dedicated Resource Imbalance sales in a separate 447xxxx account.
574	4470150	Transm. Rev.-Dedic. Whlsl/Muni	To record non-affiliated transmission revenues associated with dedicated energy sales to wholesale municipal customers and public authorities.
575	4470175	OSS Sharing Reclass - Retail	For earnings release reporting only. To record and reflect the estimated amount of OSS margin shared with retail ratepayers. This account is mapped to the retail lines of the earnings release. The amount recorded in the account will be equal to and offsetting of the amount recorded in OSS Sharing Reclass - Reduction.
576	4470176	OSS Sharing Reclass-Reduction	For earnings release reporting only.This account will record and reflect the estimated amount of OSS margin shared with retail ratepayers. This account is mapped to the Off-System Sales line of the earnings release in order to reflect that line net of OSS margin sharing. The amount recorded in the account will be equal to and offsetting of the amount recorded in OSS Sharing Reclass - Retail
577	4470219	Merchant Fuel Revenue	This account is used to record the Fuel Revenue associated with Merchant Sales.
578	4470223	Merchant Sales Margin	This account is used to record the Merchant Sales Margin associated with Merchant Sales.
579	4470320	SPP Net Regulation OSS	To accommodate Off System Sales (OSS) Net Regulation in the new SPP Integrated Market so amounts are presented in the correct EEI Reporting line.
580	4470321	SPP Net Spinning Reserve OSS	To accommodate Off System Sales (OSS) Net Spinning Reserve in the new SPP Integrated Market so amounts are presented in the correct EEI Reporting line.
581	4470324	SPP Net Supp Reserve OSS	To accommodate Off System Sales (OSS) Net Supply Reserve in the new SPP Integrated Market so amounts are presented in the correct EEI Reporting line.
582	4470326	SPP Net Marginal Losses OSS	To accommodate Off System Sales (OSS) Net Marginal Losses in the new SPP Integrated Market so amounts are presented in the correct EEI Reporting line.
583	4470328	SPP Net Make Whole Payment OSS	To accommodate Off System Sales (OSS) Net Make Whole Payment in the new SPP Integrated Market so amounts are presented in the correct EEI Reporting line.
584	4470332	SPP Congestion Costs OSS	To accommodate Off System Sales (OSS) Congestion Costs in the new SPP Integrated Market so amounts are presented in the correct EEI Reporting line.
585	4491002	Prov Rate Refund-Nonaffiliated	This account shall be charged with provisions for the estimated pretax effects on net income of the portions of amounts being collected subject to refund which are estimated to be required to be refunded to nonaffiliated
586	4491003	Prov Rate Refund - Retail	This account is used to track Prov Rate Refund - Retail
587	4491004	Prov Rate Refund - Affiliated	This account shall be charged with provisions for the estimated pretax effects on net income of the portions of amounts being collected subject to refund which are estimated to be required to be refunded to affiliated companies.
588	4491018	Prov Rate Refund - Tax Reform	With the passage of the Tax Cuts and Jobs Act of 2017, the AEP regulated subsidiaries will need to defer (prov for refund) a portion of their revenues to accommodate the reduction of the corporate tax rate from 35 to 21%. The time frame of the deferral will vary by company as the new tax rate is incorporated into the customer rates over time. The offset will be recorded in 229xxxx.
589	4491019	Prov Rate Refund-Exces Protect	With the passage of the Tax Cuts and Jobs Act, the regulated subsidiaries are required to pass back the protected portion of the excess ADIT, effective 1/2018, in the tax provision system. This account and an associated 229 account will offset/feedback the effect of this tax transaction until the excess is actually returned to the customers.

Southerwestern Electric Power Company **Schedule E-9**
Chart of Accounts
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
590	4500000	Forfeited Discounts	This account shall include the amount of discounts forfeited or additional charges imposed because of the failure of customers to pay their electric bills on or before a specified date.
591	4510001	Misc Service Rev - Nonaffil	This account shall include revenues for all miscellaneous services and charges billed to customers which are not specifically provided for in other accounts
592	4540001	Rent From Elect Property - Af	This account shall include rents received from associated companies for the use of land, buildings, and other
593	4540002	Rent From Elect Property-NAC	This account shall include rents received from non-associated companies for the use of land, buildings, and other property.
594	4540004	Rent From Elect Prop-ABD-Nonaf	This account shall include rents received from nonassociated companies for the use of land, buildings, and other property associated with Associated Business Development activities.
595	4540005	Rent from Elec Prop-Pole Attch	This account shall include rents received from non-associated companies in connection with joint use and pole attachment rental contracts.
596	4560010	Oth Elect Rev - Royalties	This account shall include other revenues derived from electric operations applicable to non-associated companies - royalties.
597	4560012	Oth Elect Rev - Nonaffiliated	This account shall include other revenues derived from electric operations applicable to nonaffiliated companies.
598	4560013	Oth Elect Rev-Trans-Nonaffil	This account shall include other revenues derived from electric operations applicable to transmission.
599	4560015	Other Electric Revenues - ABD	This account shall include other revenues derived from electric operations applicable to Associated Business Development.
			This account is intended solely for use by CSW Energy, CSW International and their subsidiaries.
600	4560025	Plant Operations O/H Revenues	This account shall contain all revenues related to revenues earned from the contractual operationns overhead billed for plants operated on behalf of external parties.
601	4560041	Miscellaneous Revenue-NonAffil	To track miscellaneous revenue from non-affiliated companies.
602	4560102	Oth Elect Rev-Trans-ERCOT area	Account is to distinguish transmission revenue charges that were originally paid to Ercot for commerical operations.
603	4561008	SPP Non-Affil. Base Fundng Rev	Non-Affiliated revenue relating to transmission group billing for SPP base funding charges. Should map to same line as 4560080. Represents Non-Affiliated Base Funding revenue that transmission group is billing SPP.
604	4561009	SPP Affil. Base Funding Cost	Affiliated SPP Base Funding charges that are being paid by the generation group. Should map to same line as 4560096. Contra revenue booked on the generation companies relating to SPP Affiliated Base Funding revenue.
605	4561010	SPP Affl. Base Funding Rev	Affiliated revenue relating to transmission group billing for SPP base funding charges that are being paid by the generation group. Should map to same line as 4560091. Represents Affiliated Base Funding revenue that transmission group is billing generation in regards to SPP. (Mapped to Transmission Line 6)
606	4561011	SPP Pt to Pt Trans Serv Rev	To differentiate firm & nonfirm point to point transmission revenue with SPP-non affiliate. BUs 169,192,194,114. Move transmission revenue from acct 4560080 to 4561xxx
607	4561012	SPP Direct Assignment	To record direct assignment revenue with SPP - Non affiliated. BU 159, 194. Move transmission revenue from acct 4560082 to 4561xxx.
608	4561013	SPP Affiliated NITS Revenue	Affiliated revenue relating to transmission group billing for Network Transmission Service charges relating to SPP that are being paid by the generation group. Move Transmission revenue from acct 4560091 to 4561
609	4561014	SPP Ancillary Services	To record SPP Non-Affiliated Ancillary Services Revenue. Move transmission revenue from acct 4560092 to 4561xxx.
610	4561015	SPP Ancillary Schedule 1	Recording ancillary charges for the transmission group specifically from the SPP line Schedule 1. Move transmission revenue from acct 4560098 to 4561xxx
611	4561016	SPP Affiliated Trans NITS Cost	Affiliated transmission cost relating to SPP that are being paid by the generation group. Contra revenue booked on the generation companies relating to SPP Affiliated NITS revenue. Move transmission revenue from acct 4560096 to 4561xxx
612	4561017	Oth Elect Revenues - Ancillary	This account shall include other revenues derived from electric operations applicable to transmission - ancillary.
613	4561021	SPP NITS	To differentiate network integration transmission SVC with SPP Non affiliated. BU 169,192,194,114. Move transmission revenue from acct 4560081 to 4561xxx
614	4561038	SPP Pt to Pt Trans Affil Cost	To differentiate firm & nonfirm point to point transmission costs with SPP as an affiliate transaction. SPP = Southwest Power Pool
615	4561039	SPP Pt to Pt Trans Affil Rev	To differentiate firm & nonfirm point to point transmission revenue with SPP-Affiliate. SPP = Southwest Power Pool.
616	4561040	Affil. SPPAncillary Sch.1 Cost	Record affiliate ancillary transmission expense from the SPP line Schedule 1. SPP = Southwest Power Pool
617	4561041	Affil. SPPAncillary Sch. 1 Rev	Record affiliate ancillary revenue for the transmission group specifically from the SPP line Schedule 1.

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Line No.	G/L Account	Account Description	Additional Description
618	4561042	SPP Base Funding - Contra	To defer the amount of 2017 SPP charges in excess of 2015 SPP charges beginning January 2017, not to exceed $4.5 Million. Amortization to begin in August 2018. Per LPSC STS Docket No. U-34200.
619	4561064	PROVISION RTO Rev WhslCus-NAf	To record the RTO provision associated with under/over collections of RTO revenue in current or prior years for Wholesale Customers (Formula Rate). This account is included in the ENEC calculation for APCo and WPCo.
620	5000000	Oper Supervision & Engineering	This account shall include the applicable portion of the cost of labor and expenses incurred in the general supervision, direction, planning, coordination, instruction and training in connection with the operation of steam power generating stations. It shall include the portion of services of personnel such as managers and assistants, supervisors, engineers, chief chemist, accounting supervisor, assistant and plant accounting personnel, secretaries and other staff employees and consultants. Include herein the general supervision and direction of work as it relates to operation only, but not the actual performance of such work or the immediate and direct supervision chargeable to other accounts appropriate for the work performed. Exclude from this account general clerical and stenographic work which is includible in Account 5060000, Miscellaneous Steam Power Expenses - All Other. Outside Services: Consultants' fees and expenses. This account is managed in ABMS. Activity and Benefiting Location are required.
621	5000001	Oper Super & Eng-RATA-Affil	This expense account will be used by the Generating companies to record the billings from USTI for the Relative Accuracy Test Audits (RATA). This is an affiliate expense account, which is established to faciliate intercompany eliminations.
622	5010000	Fuel	This account shall include the cost of labor, materials used, and expenses incurred in connection with fuel consumed which are not provided for in accounts 5010001, 5010003, 5010005, 5010008, 5010009, 5010010, 5010011, 5010012, or 5010013 (e.g. labor, materials, and expenses incurred in connection with ash disposal.) average delivered cost per ton at the close of the current month. Note: No direct charges are to be made to this account. Costs for activities described below will be initially recorded in Account 1510000, Fuel Stock. Coal - invoice cost. Discount expense on coal and freight invoices. Freight, switching, barging, demurrage, and other transportation and related taxes. Fuel oil - invoice cost Inventory adjustments to correct overages and shortages. Liability insurance on cargo and barge operations. Natural gas - invoice cost. Tipple and dumping charges on transfers from railroad cars to barges. Note: Invoice cost of coal, where appropriate, includes charges such as: Amortization of conveyor land Mine coal conveyor operation and maintenance Depletion of coal resources. Depreciation on equipment investment. Reclamation expense and cost of license. Real property taxes rental income and miscellaneous expenses.
623	5010001	Fuel Consumed	

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Line No.	G/L Account	Account Description	Additional Description
624	5010003	Fuel - Procure Unload & Handle	This account shall include the cost of labor, materials used and expenses incurred in procuring, unloading and handling fuel consumed as cleared from Account 1520000, Fuel Stock Expenses Undistributed at the average cost per ton at the close of the current month. No direct charges are to be made to this account. Costs for activities described below will be initially recorded in Account 1520000, Fuel Stock Expenses Undistributed. 1. Labor and expenses associated with investigating sources of coal, fuel oil and natural gas supply, procurement activities, and the negotiation of contracts . 2. Checking moisture content of coal pile. 3. Controlling dust from coal in storage. 4. Cleaning coal bunkers to prevent or release jams. 5. Handling fuel from storage of shipping facility to bunker in the boiler house structure. 6. Moving coal in storage pile for fire prevention purposes. 7. Packing coal pile. 8. Processing invoices and related records for fuel placed in stock but excluding reports and records of fuel consumed. 9. Routine analysis of fuel before being consumed. 10. Routine testing and calibrating of coal conveyor scales and fuel meters and gauges. 11. Surveying coal pile and measuring fuel storage tanks. 12. Unloading fuel shipment from cars, barges or trucks into storage. 13. Weighing and recording truck coal. 14. Oil for thawing coal in coal cars or barges. 15. Rent of leased coal handling and storage equipment. 16. Stores expenses applicable to fuel. 17. Tools, lubricants, fuel and miscellaneous supplies used in connection with analyzing coal, dust control, packing and surveying coal pile, measuring fuel storage tanks, and operating coal handling equipment. Note: A. Operating fuel conveying, storage, weighing and processing equipment within the boiler plant shall be charged to account 5020000, Other Steam Expenses. B. Maintenance of fuel handling equipment shall be charged to Account 5120000 Maintenance of Boiler Plant.
625	5010012	Ash Sales Proceeds	This account will be used to segregate ash sales proceeds from ash disposal expenses.
626	5010013	Fuel Survey Activity	This account will be used for the distribution of Fuel Survey charges recorded by journal entry prepared by Fuel Accounting.
627	5010018	Lignite Consumed	This account is used to track Lignite Consumed
628	5010019	Fuel Oil Consumed	This account is used to track Fuel Oil Consumed
629	5010020	Nat Gas Consumed Steam	This account is used to record gas expenses at gas steam units. Changed title and description per CF #7053 on 2/1/10.
630	5010021	Transp Gas Consumed Steam	This account is used to record transportation for gas consumed at gas steam units. Changed description per CF#7053 effective 2/1/10. Prior description - This account will be used to record activity related to Gas Transportation Expenses
631	5010027	Gypsum handling/disposal costs	The account shall include the labor, material and expenses incurred for handling and disposal of gypsum from the FDG equipment
632	5010034	Gas Transp Res Fees-Steam	To record pipeline transportation reservation fees on gas steam boiler units.
633	5010035	Gas Transp Res Fees - CC	To record pipeline transportation reservation fees on gas combined cycle units.
634	5010036	Nat Gas Consumed CC	This account is used to record gas expenses for combined cycle units.
635	5010037	Transportation Gas CC	This account is used to record transportation for gas consumed at combined cycle units.
636	5020000	Steam Expenses	This account shall include the cost of labor, materials used and expenses incurred in production of steam for electric generation. Payroll Labor: Analyzing and treating water Cleaning filters Operating chlorinators Operating pumping station Pumping boiler compounds Unloading compound from cars to storage or tanks. Monitoring pollution Operating ash handling equipment Material: Boiler compounds Chemicals for analysis Chlorine and other chemicals Pumping supplies Water Note: Do not include in this account water used for general station purposes or the cost of maintaining water supply systems.
637	5020001	Lime Expense	This account is for recording lime used in the scrubbers to remove impurties in the emissions produced by the plants. The expense associated with Lime is increasing substantially and is a function of Scrubber and SCR
638	5020002	Urea Expense	This account is for recording urea used in the SCR's to remove impurties in the emissions produced by the plants. The expense associated with Urea is increasing substantially and is a function of Scrubber and SCR installations.
639	5020003	Trona Expense	This account is for recording Trona used in the SCR's to remove impurities in the emissions produced by the plants. The expense associated with TRONA is increasing substantially and is a function of Scrubber and SCR installations.
640	5020004	Limestone Expense	This account is to record use of limestone in either the FGD or combustion processes to help control the quality of emissions produced.
641	5020005	Polymer expense	This account is used by the power plants to capture the cost of polymer purchases. Polymers attract pollutants from scrubber waste.
642	5020006	Consumable Expense-Deferred	To defer environmentally related consumable expenses for future recovery through Virginia/Arkansas Environmental & Reliability cost recovery mechanism in account 502 normally as a credit.

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Line No.	G/L Account	Account Description	Additional Description
643	5020007	Lime Hydrate Expense	Beginning January 2007, AEP will be receiving a new consumable called Lime Hydrate. Lime Hydrate will be trucked to the plants in small quantities and consumed upon receipt. Lime Hydrate is a mixture of lime (CaO) and water (H_2O) used in the Flue Gas Desulfurization process waste water treatment plant to treat the acidity in the waste (landfill) stream.
644	5020008	Activated Carbon	Capture costs associated with the purchase and transportation of Activated Carbon. This product will be used for mitigating Mercury emissions at Coal Fired Power Plants. This cost will start in 2010, but for forecasting/budgeting purposes we need the account established now.
645	5020013	Anhydrous Ammonia Expense	This account is for recording anhydrous ammonia used to control nitrogen oxide emissions produced by the plants. ITEMS Labor: 1. Procuring and handling of Anhydrous Ammonia. 2. All routine Anhydrous Ammonia analyses. 3. Unloading from shipping facility and putting in storage. 4. Moving of Anhydrous Ammonia in storage and transferring from one station to another. 5. Handling from storage or shipping facility to first bunker, hopper, bucket, tank, or holder of boiler house structure. 6. Operation of mechanical equipment, such as locomotives, trucks, cars, boats, barges, cranes, etc. Supplies and Expenses: 1. Tools, lubricants and other supplies. 2. Operating supplies for mechanical equipment. 3. Transportation and other expenses in moving Anhydrous Ammonia. 4. Stores expenses applicable to Anhydrous Ammonia.
646	5020014	Calcium Bromide Expense	This account will record the expense of the use of calcium bromide in a Dry Sorbent Injection process to reduce mercury emmissions.
647	5020016	Dolet Hills Misc Reagents	This account records miscellaneous Dolet Hills recoverable reagent/consumable expense including Dibasic Acid, Dust Suppression, Sand, Aqua Ammonia, Sodium Carbonate, and Emulsified Sulfur.This excludes those reagents/consumables recorded in accounts 5020002 (Urea), 5020003 (Trona), 5020005 (Thickener Polymer), 5020007 (Hydrated Lime), 5020008 (Activated Carbon), 5020013 (Anhydrous Ammonia), and 5020028 (Sodium Bicarbonate).
648	5020025	Steam Exp Environmental	This account shall include the portion of costs related to any environmental projects that would otherwise be charged to account 5020000. This excludes costs for lime that are charged to 5020001, urea charged to 5020002, trona charged to 5020003 or limes.
649	5050000	Electric Expenses	This account shall include the cost of labor, materials used and expenses incurred in operating prime movers, generators, and their auxiliary apparatus, switch gear and other electric equipment to the points where electricity leaves for conversion for transmission or distribution. Payroll Labor: Inspecting, checking, testing and operating the following: Control valves (without disassembly). Condensers, circulating water systems and other auxiliary apparatus. Crib house water alarm. Generator cooling system. Meters, gauges and instruments. Turbine generator units and associated auxiliaries. Also include herein: Changing charts on recording and measuring devices. Replenishing nitrogen gas to maintain pressure. Material: Circulating water purification supplies. Cooling water purchased. Generator cooling, gases, hydrogen. Generator and motor brushes. Gauge glasses and

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Line No.	G/L Account	Account Description	Additional Description
650	5060000	Misc Steam Power Expenses	This account shall include the cost of labor, materials used and expenses incurred in the operation of steam power generating stations which are not specifically provided for or not readily assignable to other steam power generating accounts. Payroll Labor: 1. Checking and filing records pertaining to plant land, boundaries, building and equipment owned by the utility and in operation. Includes deeds and easements previously acquired. 2. Preparing, maintaining and filing: Details for yearly tax reports. Operation and maintenance forecasts and reports. Time reports and payroll records Work orders and completion reports. Activities relating to air and water pollution control such as: Recording results of chemical analysis. Preparing and filing reports and applications. Operation of refuse water treatment system. Other Labor: 1. Care of grounds including snow removal, cutting grass, etc. 2. Building service including cleaning floors, washing windows, insect control, etc. 3. Inspecting and repairing small hand tools and general use. 4. Inspecting all fire extinguishers and refilling those under 15 lbs. (dry) and under 2-1/2 gallons (liquid). 5. Guarding and patrolling station and yard. 6. Taking temperature reading of the river for possible contamination. 7. Clean septic tanks. Materials: 1. Cafeteria supplies 2. Fuel for heating 3. Gaskets, gauge glasses (Note A) 4. General laboratory supplies 5. Guard Uniforms 6. Janitor supplies 7. Lamps - indicating 8. Light Bulbs 9. Log sheets and charts 10. Meter supplies 11. Office supplies 12. Packing 13. Rope 14. Small fire extinguishers 15. Tools-small, portable (Note B) 16. Refills for fire extinguishers 17. Training materials and supplies All Other: 1. Communication Service 2. Postage 3. Research and Development expenses 4. Costs related to the Amos Simulator as billed to the AEP System generating plants by Appalachian and Ohio Power Companies. Note: Special gauge glasses and special gaskets which are purchased for particular equipment, and are relatively expensive and generally installed by maintenance labor, shall be charged to the appropriate maintenance accounts. Cost of and repairs to small tools used exclusively for maintenance should be charged to the maintenance accounts appropriate for the equipment. This account includes the cost of individual business and professional memberships; see Account 4265004 for social memberships and related expenses and see Account 9302000 for corporate memberships such as for industry dues, e.g., EEI.
651	5060001	Dresden Misc Steam Pwer Exp	APCo's Virginia Generation Rate Adjustment Clause (G-RAC original case number PUE-2011-00036), and West Virginia Expanded Net Energy Costs (ENEC original Case number 11-0265-E-PC) related to miscellaneous steam power expense associated with the Dresden Generating Plant over/under accounting. Subsequent case numbers will not be included in this description.
652	5060003	Removal Cost Expense - Steam	For AEP's non-regulated companies, expensing of costs related to the removal of the Company's property, plant and equipment in accordance with FASB 143. A new account sub-point needs to be established under account 506 for the non-regulated steam generation companies, also a new account sub-point is needed under account 859 for the gas transportation companies and a new sub-point for LIG Liquids under account 776.
653	5070000	Rents	This account shall include all rents of property, used, occupied, or operated in connection with steam power generation including rents paid to associated companies on spare parts, such as interchangeable turbine rotors, accessories and other equipment used, or held for use, in connection with steam power generation. All Other: Rents paid to others for the use of buildings. Rents paid to others for the use of land and rights-of-way.
654	5070006	Rents - Associated	To record inter-company rent transactions for usage of buildings by associated companies that have no ownership interest in the building.
655	5080017	IPP Oper - Training/Travel	This account is intended solely for use by CSW Energy, CSW International and their subsidiaries.
656	5090001	Allowance Consumption - NOx	This account will track the Consumption cost attributed with NOx allowances for compliance
657	5090002	Allowance Expenses	To record expenses related to EPA Allowances not directly assignable to Consumption
658	5090008	Deferred Enviro Emission Costs	Defer Environmental Emission Cost related to the Environmental Adjustment Clause and Environmental Certification Rule (EAC Rule). The EAC Rule applies to only those pollutants regulated by the United States EPA at the time of Commission adoption, namely, SO2 and NOx. Utilities are required to make a specific request before any other environmental cost for new pollutants can be recovered under the EAC, such as greenhouse gas emission under the Clean Air Act, or any new Federal Legislation.
659	5090012	CSAPR AN NOx Cons. Exp	This account will track the consumption cost attributed with Cross State Air Pollution Rule (CSAPR) Annual NOx allowances for compliance purposes
660	5090013	CSAPR Seasonal NOx Cons. Exp	This Account will track the consumption cost attributted with Cross State Air Pollution Rule (CSAPR) seasonal NOx allowances for compliance purposes

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Line No.	G/L Account	Account Description	Additional Description
661	5100000	Maint Supv & Engineering	This account shall include the applicable portion of the cost of labor and expenses incurred in the general supervision, direction, planning coordination, instruction and training in connection with the maintenance of steam power generating stations, but not the actual performance of such maintenance work itself or the immediate and direct supervision chargeable to other accounts appropriate for the work performed. It shall include the portion of services of personnel such as managers and assistants, supervisors, engineers, chief chemist, accounting supervisor, assistant and plant accounting personnel (except general and stenographic work directly assignable to other specific activities) secretaries and staff employees and consultants.
662	5100001	Dresden Maint Sup& Engineer	APCo's Virginia Generation Rate Adjustment Clause (G-RAC original case number PUE-2011-00036), and West Virginia Expanded Net Energy Costs (ENEC original Case number 11-0265-E-PC) related to general supervision, direction, planning coordination, instruction and training in connection with the maintenance of steam power generating station expenses associated with the Dresden Generating Plant over/under accounting. Subsequent case numbers will not be included in this description.
663	5110000	Maintenance of Structures	This account shall include the cost of labor, materials used, and expenses incurred in the maintenance of buildings, structures, fixtures and improvements at steam power generating stations, the book cost of which is includible in Account 311, Structures and Improvements. Detail breakdown of this account can be obtained from the equipment class field of the Activity Based Management System (ABMS).
664	5120000	Maintenance of Boiler Plant	This account shall include the cost of labor, materials used, and expenses incurred in the maintenance of boiler plant equipment at steam power generating stations, the book cost of which is includible in Account 312, Boiler Plant Equipment. Detail breakdown of this account can be obtained from the equipment class field of the Activity Based Management System (ABMS).
665	5120025	Maint of Blr Plt Environmental	This account shall include the portion of costs related to any environmental projects that would otherwise be charged to account 5120000.
666	5130000	Maintenance of Electric Plant	This account shall include the cost of labor, material used, and expenses incurred in the maintenance of steam turbines, generators and generator units, auxiliary apparatus, and accessory electric equipment, the book cost of which is includible in account 313, 314, and 315. Detail breakdown of this account can be obtained from the equipment class field of the Activity Based Management System (ABMS).
667	5140000	Maintenance of Misc Steam Plt	This account shall include the cost of labor, materials used, and expenses incurred in the maintenance of miscellaneous steam power generating station equipment, the book cost of which is includible in Account 316, Miscellaneous Power Plant Equipment. Detail breakdown of this account can be obtained from the equipment class field of the Activity Based Management System (ABMS).
668	5460000	Oper Supervision & Engineering	This account shall include the cost of labor and expenses incurred in the general supervision and direction of the operation of other power generating stations. Direct supervision of specific activities such as fuel handling, engine and generator operation, etc., shall be charged to the appropriate account.
669	5470001	Fuel - Gas Turbine	This account shall include the cost delivered at the station of all fuel used in gas turbines.
670	5470003	Gas Transp Res Fees - CT	To record pipeline transportation reservation fees on gas combustion turbine units
671	5470004	Fuel - Gas Turb - Purch / Hand	To track purchasing and handling costs related to fuel for gas turbines
672	5470005	Gas Transp Fees - CT	To record pipeline transportation fees on gas combustion turbine (CT) units.
			This account shall include the cost of labor, materials used, and expenses incurred in operating prime movers, generators, and electric equipment in other power generating stations, to the point where electricity leaves for conversion for transmission or distribution. Payroll Labor: Supervising other power generation operation. Operating prime movers, generators, and auxiliary apparatus, switching, and other electric equipment. Keeping plant log and records, and preparing reports on plant operations. Testing, checking, cleaning, oiling, and adjusting equipment. Materials and Expenses: Dynamo, motor, and generator brushes. Lubricants and control system oils. Water for cooling engines and generators.
673	5480000	Generation Expenses	This account was inactive between 12/1/1999 and 1/1/2001. It was reactivated to meet CSW mapping requirements.

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Line No.	G/L Account	Account Description	Additional Description
674	5490000	Misc Other Pwer Generation Exp	This account shall include the cost of labor, materials used, and expenses incurred in the operation of other power generating stations which are not specifically provided for or are not readily assignable to other generation expense accounts. Payroll Labor: General clerical and stenographic work. Guarding and patrolling plant and yard. Building service. Care of grounds, including snow removal, cutting grass, etc. Miscellaneous labor. Material and Expenses: Building service supplies. First aid supplies and safety equipment. Communication service. Employees' service facilities expenses. Office supplies Transportation expense. Meals, traveling, and incidental expenses. Fuel for heating. Water for fire protection or general use. Miscellaneous supplies such as hand tools, etc. This account was inactive from 12/1/1999 through 9/1/2000.
675	5530001	Maint of Gen Plant - Gas Turb	This account shall include the cost of labor, materials used and expenses incurred in maintenance of plant applicable to gas turbines, the book cost of which is includible in account 343, Prime Movers, account 344. Generators, and account 345, Accessory Electric Equipment.
676	5540001	Maint of Oth Pwr Gen Plt-GT	This account shall include the cost of labor, materials used and expenses incurred in maintenance of gas turbine power generation plant, the book cost of which is includible in account 346, Miscellaneous Power Plant Equipment.
677	5550000	Purchased Power	This account shall include the cost, at the point of delivery, to the utility, of electricity purchased for resale, including charges for readiness to serve.
678	5550001	Purch Pwr-NonTrading-Nonassoc	This account shall include the cost at the point of delivery of non-trading power purchased for resale. this includes: (1) OVEC Purchases pursuant to Section 9.01 of the Intercompany Power Agreement dated July 10, 1953 (2) System Purchases to serve Internal Load.
679	5550003	Purchased Power - Cogeneration	This account shall include the amounts charged for energy received from non-associated companies, under interchange agreements, whereby the utility both delivers energy to and receives energy from another for the purpose of achieving efficient utilization of productive capacity. Records shall be maintained to show, by months, the charges under each interchange agreement.
680	5550023	Purch Power Capacity -NA	This account is used to track Purch Power Capacity -NA
681	5550024	Purchase Power ERCOT	This account is used to track Purchase Power ERCOT
682	5550026	Purchase Power - Fuel - ERCOT	This account will be used to record activity related to Purchase Power - Fuel - ERCOT
683	5550032	Gas-Conversion-Mone Plant	To record labor, capacity and M&S charges for Mone Plant
684	5550047	Purchase Power Wind Energy	REcord the purchase of Wind Energy
685	5550054	Purch Power ERCOT-Non-ded	This account is used to track Purchase Power ERCOT - Non-dedicated
686	5550066	SPP Rev. Neutrality Ded-Purch	To record SPP Dedicated Revenue Neutrality purchases in a separate 555xxxx account.
687	5550113	Cleco PP for Valley - Other	This account will used to capture the OTHER charges of the purchase power. Vemco was purchased by SWEPCO in Oct. 2010. VEMCO has a long term PP agreement with Cleco which needs to be separately reported for regulatory recovery in LA
688	5550128	SPP Net Purch that serve OSS	This account shall include only the value of SPP net purchases on an hourly or 5 min interval that serve off system sales for PSO and SWEPCO. This account is to be used to report in FERC Form1 (Annual) and Form3 (Quarterly) reports (effective beginning April 1, 2014) amounts applicable to net hourly or 5 min interval purcahse amounts which should be reported to the FERC as being in account 555 Purchase Power. Note: Financial Reporting should map this account to Operating Revenue for SEC reporting purposes. This activity should continue to be netted in revenue per accounting policy.
689	5550130	SPP Net Marginal Losses LSE	To accommodate Load Serving Entity (LSE) Net Marginal Losses in the SPP Integrated Market so amounts are presented in the correct EEI Reporting line.
690	5550131	SPP Congestion Costs LSE	To accomodate Load Serving Entity (LSE) Congestion Costs in the SPP Integrated Market so amounts are presented in the correct EEI Reporting line.
691	5550133	SPP TCR's & ARR's LSE	To accommodate Load Serving Entity (LSE) Transmission Congestion Rights (TCR) and Auctions Revenue Rights (ARR) in the SPP Integrated Market so amounts are presented in the correct EEI Reporting line.
692	5550136	SPP MakeWholePymt Charge Gross	To record Load Serving Entity (LSE) Gross Make Whole Payment Charges in the SPP Integrated Market
693	5550138	SPP MakeWholePymt Credit (Net)	To accommodate Load Serving Entity (LSE) Net Make Whole Payment in the new SPP Integrated Market so amounts are presented in the correct EEI Reporting line.
694	5550320	SPP Net Regulation LSE	To accommodate Load Serving Entity (LSE) Net Regulation in the new SPP Integrated Market so amounts are presented in the correct EEI Reporting line.

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Line No.	G/L Account	Account Description	Additional Description
695	5550321	SPP Net Spinning Reserve LSE	To accommodate Load Serving Entity (LSE) Net Spinning Reserve in the new SPP Integrated Market so amounts are presented in the correct EEI Reporting line.
696	5550324	SPP Net Supp Reserve LSE	To accommodate Load Serving Entity (LSE) Net Supply Reserve in the new SPP Integrated Market so amounts are presented in the correct EEI Reporting line.
697	5550325	SPP Contingency Costs LSE	To accommodate Load Serving Entity (LSE) Contingency Costs in the new SPP Integrated Market so amounts are presented in the correct EEI Reporting line.
698	5560000	Sys Control & Load Dispatching	This account shall include the applicable portion of the salaries and expenses incurred by personnel of the System Operating Department in the performance of duties and responsibilities in connection with system control and load dispatching relating to the generating function. Utilities having an interconnected electric system (as exits in AEP System) or operating under a central authority which controls the production and dispatching of electricity may apportion these costs to this account and Account 5610000, Load Dispatching - Transmission and Account 5810000, Load Dispatching - Distribution. Also include in this account the applicable portion of salaries and expenses (includes Moving Expenses) of personnel of the System Operating Department such as: Chief System Load Coordinator (Chief System Load Dispatchers) System Load Coordinator (System Load Dispatcher) Chief Regional Dispatcher at generating station Regional Dispatchers (Station Operators) at generating stations Where, due to organizational structure, employees of the System Operating Department perform duties directly related to Human Resources Department functions, such portion of their salaries and expenses applicable should be charged to the Human Resources Department function accounts appropriate. Payroll Labor: 1. Allocating loads to plants and interconnections with others. 2. Arranging and controlling clearances for construction, maintenance, test and emergency purposes. 3. Assisting with educational program of job training for system operators, load dispatchers and plant operators. 4. Calculating steam requirements in relation to system loading of plants. 5. Calculating steam and hydraulic production cost rates including interchange. 6. Contact other utilities on energy transfer, purchase, sales and reactive interchange. 7. Controlling system voltages. 8. Directing switching. 9. Follow meteorological data system daily in connection with hydro plant operation. 10. Handle contracts pertaining to hydro operation with governmental authorities. 11. Hydro plant scheduling in maintaining reservoir level at various hydro plants. 12. Obtaining reports on weather and special events. 13. Preparing, checking, reviewing or supervising: A. Cost analysis and savings on purchase and interchange with other companies. B. Generating Equipment Service Record - Turbines and Boilers from daily logs. C. Interchange statements covering capacity and energy transactions with associated and foreign utilities. D. Load data reports, system load forecasts, etc. E. Operating practices and procedures for changes and revisions and reviewing with operating personnel. (steam and hydro) F. Plant summaries, operating performance, costs and data for billing and budget purposes. G. Production and operating cost reports and comparative statements for past periods. H. Summaries of energy classifications in pool and interchange accounts. I. Switching diagrams for expansion of plant before actual operation. J. Work on incremental plant studies.
699	5570000	Other Expenses	This account shall be charged with any production expenses, including expenses incurred directly in connection with the purchase of electricity, which are not specifically provided for in the other production expense accounts. Charges to this account shall be supported so that a description of each type of charge will be readily available. Payroll Labor: Charge hereto the cost of labor incurred in relation to cogeneration, independent power producers, and small power producers (excluding activities performed with customers having parallel generation). Chargeable activities include: Planning and coordinating activities related to purchasing or wheeling power from a proposed project. Billing purchased power or wheeling charges. Service arrangement for the installation or maintenance of such a project. Documenting project events, status, etc., estimates, contracts, and reports.
700	5570004	Deferred Fuel	This account is used to track Deferred Fuel
701	5570010	OH Auction Exp - Incremental	To record incremental Ohio Auction related expenses which are expected to be recovered from Ohio FAC ratepayers. This account should be mapped to Other Generation Op Exp (Other Operation) for SEC reporting.

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
702	5600000	Oper Supervision & Engineering	This account shall include the applicable portion of the cost of labor and expenses incurred in the general supervision, direction, planning, coordination, instruction and training in connection with the operation of the transmission system. It shall include the portion of services of personnel such as the System, Division and District Supervisors, Engineers, Superintendents, General Foremen, Consultants and Secretarial work for this group. Include herein the general supervision and direction of work as it relates to operation only, but not the actual performance of such work or the immediate and direct supervision chargeable to other accounts appropriate for the work performed. In the case of fixed classification employees, such percentage of their time applicable, as determined by periodic time studies, shall be classified to the intercompany overhead work orders established under Account 10710, Construction Work in Progress and sub account 108XXXX, Retirement Work in Progress under Account 108, Accumulated Provision for Depreciation of Electric Plant in Service. Exclude from this account general clerical and stenographic work includible in Account 5660000, Miscellaneous Transmission Expenses - All
703	5611000	Load Dispatch - Reliability	New Transmission Accounts required to comply with FERC Orders 668 and 668-A. Please note that the new Accounts 561.X are replacing current PeopleSoft Account 5610000. No later than after 2006 is closed, we will want to invalidate Account 5610000. If any charges do trickle into 5610000 in 2007, they should be reclassified to the new PeopleSoft account for FERC Account 561.2, and then Account 5610000 should be permanently inactivated.
704	5612000	Load Dispatch-Mntr&Op TransSys	New Transmission Accounts required to comply with FERC Orders 668 and 668-A. Please note that the new Accounts 561.X are replacing current PeopleSoft Account 5610000. No later than after 2006 is closed, we will want to invalidate Account 5610000. If any charges do trickle into 5610000 in 2007, they should be reclassified to the new PeopleSoft account for FERC Account 561.2, and then Account 5610000 should be permanently inactivated.
705	5613000	Load Dispatch-Trans Srvc&Sched	New Transmission Accounts required to comply with FERC Orders 668 and 668-A. Please note that the new Accounts 561.X are replacing current PeopleSoft Account 5610000. No later than after 2006 is closed, we will want to invalidate Account 5610000. If any charges do trickle into 5610000 in 2007, they should be reclassified to the new PeopleSoft account for FERC Account 561.2, and then Account 5610000 should be permanently inactivated.
706	5614002	SPP Admin-SSC&DS	SPP administrative service fees for scheduling, system control and dispatching services. This account shall include the costs billed to the transmission owner, load serving entity or generator for scheduling, system control and dispatching service. Include in this account service billings for system control to maintain the reliability of the transmission area in accordance with reliability standards, maintaining defined voltage profiles, and monitoring operations of the transmission facilities.
707	5614005	ERCOT Admin-SSC&DS	ERCOT administrative service fees for scheduling, system control and dispatching services. This account shall include the costs billed to the transmission owner, load serving entity or generator for scheduling, system control and dispatching service. Include in this account service billings for system control to maintain the reliability of the transmission area in accordance with reliability standards, maintaining defined voltage profiles, and monitoring operations of the transmission facilities. New FERC rules require recording administration fees for RTO's to new accounts.
708	5614006	SPP Transmission Charges	This account will record Non-Admin fee SPP transmission charges, such as point to point transmission costs and impact studies.
709	5614007	RTO Admin Default LSE.	To record RTO costs when a market participant defaults on its payment obligations with the RTO and is socialized across all participants. This administrative fee relates to the LSE (load serving entity)
710	5615000	Reliability,Plng&Stds Develop	New Transmission Accounts required to comply with FERC Orders 668 and 668-A. This account is initially to apply to RTOs only, since RTOs would likely be performing this work. The FERC in its final order concluded that to the extent a utility performs similar work, the utility also must use Account 561.5. Please note that the new Accounts 561.X are replacing current PeopleSoft Account 5610000. No later than after 2006 is closed, we will want to invalidate Account 5610000. If any charges do trickle into 5610000 in 2007, they should be reclassified to the new PeopleSoft account for FERC Account 561.2, and then Account 5610000 should be permanently inactivated.
711	5616000	Transmission Service Studies	New Transmission Accounts required to comply with FERC Orders 668 and 668-A. This new account is to record the cost of studies for transmission service request and generator service request, respectively. Studies that are reimbursable from a specific customer should be initially charged to account 186, Miscellaneous Deferred Debits, subject to billing in Account 143, Other Accounts Receivable, and studies associated with a capital project should be charged in accordance with property accounting procedures.

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Line No.	G/L Account	Account Description	Additional Description
712	5618002	SPP Admin-RP&SDS	SPP administrative service fees for reliability planning and standards development services. This account shall include the costs billed to the transmission owner, load serving entity, or generator for system planning of the interconnected bulk electric transmission system. Include also the costs billed by the regional transmission service provider for system reliability and resource planning to develop long-term strategies to meet customer demand and energy requirements. This account shall also include fees and expenses for outside services incurred by the regional transmission service provider and billed to the load serving entity, transmission owner or generator.
713	5620001	Station Expenses - Nonassoc	transmission substations and switching stations, the book cost of which is includible in Account 353, Station Equipment. If transmission station equipment is located in or adjacent to a generating station, the cost of labor, material used and expenses incurred applicable to transmission operation shall be charged to this account. Payroll Labor: 1. Adjusting station equipment where such adjustment primarily affects performance, such as regulating the flow of a coolant, changing voltage of regulator or changing taps or connections on station transformers. Also inspecting, testing and calibrating station equipment for the purpose of checking its performance. Note: When the foregoing work requires extensive disassembling and reassembling of equipment,is done to prevent or correct trouble or failure, or is incidental to maintenance work, it should be charged to the appropriate maintenance account. 2. Clearing snow or ice from transmission station walks, roads or parking areas. 3. Cleaning grounds and station buildings, including janitor service. 4. General inspection of transmission stations. 5. Guarding and patrolling station equipment and yard. 6. Inspecting and servicing storage batteries. 7. Inspecting, cleaning and keeping record of tools used around station. 8. Inspecting all fire extinguishers and refilling those under 15 lbs. (dry) and under 2-1/2 gallons (liquid). Note:Refilling fire extinguishers larger than 1 quart size and the cost of chemical used shall be charged to the maintenance account appropriate for their use. 9. Mowing grass, weeding, attending flowers and shrubbery, etc. 10. Oiling and greasing equipment when done as part of routine operation. 11. Operating switching and other station equipment. 12. Preparing station log, records and special reports associated with the operation of transmission station equipment. 13. Reading station meters (other than customer metering). 14. Removing foreign objects from transmission station equipment, such as kites, tree branches, etc., when done incidental to regular operating duties. 15. Replacing burned out lamps. 16. Reporting load conditions or requirements as requested. 17. Resetting and winding time clocks for station lights. 18. Routine check of load or voltage. 19. Routine checking, inspecting and testing at transmission stations for radio and television interference. 20. Sampling and testing lubricants or hydraulic control oils. (Sampling and testing insulating oils should be charged to maintenance.) 21. Switching to clear lines for repair or inspection. (Time of diversified employees shall be charged to Account 5710006, Maintenance of Overhead Conductors and Devices.) 22. Testing public telephone at transmission station. 23. Watch engineer at transmission station. 24. Calibrate relays, potential devices. 25. Check automatic reclosing of oil and air circuit breakers with respect to performance of relays. 26. Check automatic operation of motor operated

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Line No.	G/L Account	Account Description	Additional Description
714	5630000	Overhead Line Expenses	This account shall include the cost of labor, materials used, and expenses incurred in the operation of overhead transmission lines. This account shall also include the cost of labor and expenses incurred in the general inspecting, testing and patrolling of transmission overhead lines when done on a routine basis for the purpose of checking the condition, efficiency and performance of property and equipment, where no trouble is known to exist or is anticipated and only relatively minor repairs and adjustments, if any, are found to be necessary. Patrolling to locate and clear known trouble should be charged to the maintenance account appropriate for the equipment. Payroll Labor: 1. Checking sleet conditions on transmission lines. 2. General inspecting and patrolling to observe the condition and performance of towers, poles, conductors and devices on overhead transmission lines. 3. Removing foreign objects such as kites, branches and birds from overhead transmission lines, incidental to routine patrolling. 4. Repairing fences or other property damaged by patrolmen on routine patrol. 5. Routine scheduled patrols. 6. Answering fire calls. 7. Electrolysis surveys. 8. Inspecting and adjusting line testing equipment, such as voltmeter, ammeters, watt meters, etc. 9. Inspecting and repairing line tools if not chargeable to maintenance. 10. Inspecting and testing lighting arresters, circuit breakers, switches and grounds. 11. Inspecting and testing transmission line insulators in storage. 12. Load test of circuits. 13. Routine checking, inspecting and testing of overhead transmission lines for radio telephone and television interference. 14. Routine voltage surveys made to determine the condition or efficiency of transmission system including installing and removing test equipment. 15. Time on duty to protect lines due to dynamiting or other nearby construction except when company construction. 16. Transferring loads, switching and reconnecting circuits and equipment for operating purposes. (Switching for construction or maintenance purposes is not includible in this account.) Outside Services: 1. Aerial patrolling. (Regular scheduled flights) Materials: 1. Operating supplies such as instrument charts, rubber goods, etc. 2. Small, portable tools, testing equipment, safety equipment, first aid kits and medical supplies.
715	5640000	Underground Line Expenses	This account shall include the cost of labor, materials used, and expenses incurred in the general inspecting and testing of transmission underground lines when done on a routine basis for the purpose of checking the condition, efficiency and performance of property and equipment, where no trouble is known to exist or is anticipated and only relatively minor repairs and adjustments, if any, are found to be necessary. Payroll Labor: 1. Electrolysis surveys. 2. Inspecting and adjusting line testing equipment such as voltmeters, ammeters, watt meters, etc. 3. Inspecting and testing lighting arresters, circuit breakers, switches and grounds. 4. Load tests of circuits. 5. Regulation and addition of oil or gas in high-voltage cable systems. 6. Routine inspection and cleaning of manholes, conduit, network and transformer vaults. 7. Routine voltage surveys made to determine the condition or efficiency of underground transmission system. Material: 1. Operating supplies such as instrument charts, rubber goods, etc. 2. Small, portable tools, testing equipment, safety equipment, first aid kits and medical
716	5650001	Transmssn Elec by Others-Assoc	This account shall include amounts payable to associated companies for the transmission of the utility's electricity over transmission facilities owned by others. All Other: 1. Payments for the use of transmission facilities.
717	5650002	Transmssn Elec by Others-NAC	This account shall include amounts payable to nonassociated companies for the transmission of the utility's electricity over transmission facilities owned by others. All Other: 1. Payments for the use of transmission
718	5650009	SPP Affiliated Transmission Ex	Expense will relate to affiliated transmission SPP expense billed by AEP transmission group for the generating companies. Activity will need to be mapped to the same financial lines as 5650001 - Transmission Elec Other - Assoc.
719	5650013	SPP Affil. Base Funding Exp	Expense will relate to affiliated SPP base funding transmission expense billed by the AEP transmission group for the generating companies. Activity will need to be mapped to same financial lines as 5650009. Represents net Affiliated SPP Base Funding expense that generation is recording. Accounting records a business unit as either a net expense or revenue (not grossed up). (Mapped to O&M expense)
720	5650014	SPP Non-Affil Base Funding Exp	Expense will relate to non-affiliated SPP base funding transmission expense billed to the generating companies. Activity will need to be mapped to same financial lines as 5650002. Represents Non-Affiliated SPP Base Funding expense. (Mapped to O&M expense)
721	5650016	PJM NITS Expense - Affiliated	To track all affiliated expenses related to PJM Network Integration Transmission Services
722	5650020	PROVISION RTO Affl Expense	To record the RTO provision associated with under/over collections of RTO revenues in current or prior years for RTO expenses.
723	5650046	SPP Transmission Expense	Transmission expense and other charges (impact studies as an example) attributed to SPP

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Line No.	G/L Account	Account Description	Additional Description
724	5650047	SPP Pt to Pt Trans Affil Exp	To differentiate firm & nonfirm point to point transmission expense with SPP as an affiliate transaction. SPP = Southwest Power Pool
725	5650048	Affil. SPPAncillary Sch. 1 Exp	Record affiliate ancillary transmission expense from the SPP line Schedule 1. SPP = Southwest Power Pool
726	5650052	SPP Transmission - Contra	To defer the amount of 2017 SPP charges in excess of 2015 SPP charges beginning January 2017, not to exceed $4.5 Million. Amortization to begin in August 2018. Per LPSC STS Docket No. U-34200.
727	5660000	Misc Transmission Expenses	This account shall include the cost of labor, materials used and expenses incurred in transmission office operations and transmission expenses not elsewhere provided for. Payroll Labor: Building service including care of grounds, snow removal, cutting grass, etc. Miscellaneous transmission labor. Time of right-of-way agent when not chargeable to a specific work order. Material: Cleaning supplies for building and yard service. Salt for water softening purposes. Small portable tools, testing equipment, safety equipment, first aid supplies. Office supplies Metal signs on right-of-way. All Other: Communication services for transmission stations and engineering offices. Leased telephone circuits Postage Leased equipment Taxes Water Research and development expenses. Note: Include herein labor and expense in connection with strike preparation applicable to the Transmission function. This account includes the cost of individual business and professional memberships; see Account 4265004 for social memberships and related expenses and see Account 9302000 for corporate memberships such as for
728	5660004	SPP FERC Assessment Fees	FERC assesment fees relating to AEP entrance into SPP RTO. Account should be reported in the 566XXXX series.
729	5660008	R.King Trans Cnter Exp - Affil	Billing of specified costs at A. Ray King Transmission Training Ctr in Pataskala to West Transmission Companies (from Ohio Power Transmission) per the AEP System Transmission Center Agreement.
730	5670001	Rents - Nonassociated	This account shall include rents of nonassociated companies property of others used, occupied or operated in connection with the transmission system. All Other: 1. Rental of buildings used for transmission system purposes. 2. Rental paid for transmission line rights-of-way. 3. Rental paid to railroads for transmission line crossing permits. Note: A. Rents paid for property devoted to operations for which clearing accounts are used shall be charged to the appropriate clearing accounts. B. Rents, which are irregular or infrequent, paid for the use of equipment on specific construction, retirement or maintenance projects, shall be charged to the accounts appropriate for the work performed. C. Exclude from this account and include in Account 5650001 or Account 5650002, Transmission of Electricity By Others, amounts payable to associated and non-associated utilities for the transmission of energy over transmission facilities owned by these other associated and non-
731	5670002	Rents - Associated	This account shall include rents of associated companies property of others used, occupied or operated in connection with the transmission system. All Other: 1. Rental of buildings used for transmission system purposes. 2. Rental paid for transmission line rights-of-way. 3. Rental paid to railroads for transmission line crossing permits. 4. Rental paid to associated companies for interchangeable spare parts and equipment. Note: A. Rents paid for property devoted to operations for which clearing accounts are used shall be charged to the appropriate clearing accounts. B. Rents, which are irregular or infrequent, paid for the use of equipment on specific construction, retirement or maintenance projects, shall be charged to the accounts appropriate for the work performed. C. Exclude from this account and include in Account 5650000, Transmission of Electricity By Others, amounts payable to associated and non-associated utilities for the transmission of energy over transmission facilities owned by these other associated and non-associated utilities.
732	5680000	Maint Supv & Engineering	This account shall include the applicable portion of the cost of labor and expenses incurred in the general supervision, direction, planning, coordination, instruction and training in connection with the maintenance of the transmission system. It shall include the portion of services of personnel such as the Region and District Supervisors, Engineers, Superintendents, General Foremen, Consultants and Secretarial work for this group. Include herein the general supervision and direction of work as it relates to maintenance only, but not the actual performance of such work or the immediate and direct supervision chargeable to other accounts appropriate for the work performed. Exclude from this account general clerical and stenographic work includible in Account 5660000, Miscellaneous Transmission Expenses - All Other. Note: For billings involving relocation of transmission facilities, the portion of the overheads added to the billings which relate to Operating Expenses is to be credited 2/3 to this account and 1/3 to Account 920003, Administrative and General Salaries Transferred. The remaining portion of the total overheads included in the billings is to be credited to Account 1080000, Retire of Electric Plant in Service.

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Line No.	G/L Account	Account Description	Additional Description
733	5690000	Maintenance of Structures	This account shall include the cost of labor, material used and expenses incurred in the maintenance of transmission structures, the book cost of which is includible in Account 352, Structures and Improvements Payroll Labor: Maintenance labor on the following equipment: Air conditioning and ventilating system. Building lighting, plumbing and heating system. Company-owned railroad siding (other than transformer track). "Danger" and warning signs. Fence enclosing land and building. Operator's cottage and grounds. Retaining walls for station land. Station buildings, control, oil storage, etc. Walks, drives and parking areas. Well pumps, piping and related equipment. Yard lighting system. Also include other maintenance labor such as: Ditching station property to maintain drainage and sewage systems. Inspecting station structure and improvements for maintenance purposes. Making and installing property corner monuments or markers at transmission stations. Repairing tools used for maintenance work. Replacing gravel on station yard or driveway and regrading. Replacing shrubbery, turf, fertilizing grass and chemical killing of weeds. Material: Lumber, gravel, plumbing supplies, etc. Small portable tools, safety equipment, first aid kits and medical supplies.
734	5691000	Maint of Computer Hardware	New Transmission accounts required to comply with FERC Orders 668 and 668-A. This account is to record Maintenance of computer hardware on a transmission General Ledger Business Unit (GLBU).
735	5692000	Maint of Computer Software	New Transmission accounts required to comply with FERC Orders 668 and 668-A. This account is to record Maintenance for computer software on a transmission General Ledger Business Unit (GLBU).
736	5693000	Maint of Communication Equip	New Transmission accounts required to comply with FERC Orders 668 and 668-A. This account is to record Maintenance of communication equipment on a transmission General Ledger Business Unit (GLBU).
737	5700000	Maint of Station Equipment	This account shall include the cost of labor, material used and expenses incurred in maintenance of equipment in transmission stations other than that provided for in the other subdivisions of Account 570, Maintenance of Station Equipment. Payroll Labor: (Maintenance labor on the following equipment) Batteries - Storage (Station control) Battery charging equipment D-C distribution panels Storage batteries Capacitor Banks Carrier Current Relaying and Telemetering Carrier current relay sets Carrier current transfer trip sets Co-axial cable Coupling capacitors Line traps and tuners Note: Maintenance of carrier current telephone equipment should be charged to Account 9350020.. Communication - Public Address System Dead-end assemblies on incoming and outgoing lines (including cleaning of insulators) Fences (isolating particular pieces of equipment) Fire Protection Equipment, including housing Piping valves Foundations for equipment Instrument transformers Lightning arresters Meters and instruments (exclude billing meters) Oil (Insulating) Handling System Motors and drives Piping (oil, also oil and water drainage) Pumps Storage tanks Testing equipment Treating equipment Power, control wiring and grounding Cable, power and control Cable trench Conduit and fittings Duct runs Ground rods, cable and connectors Junction boxes Manholes Potheads Structures Structural steel Wood pole Fire walls Stairs and platforms Switchboards Meters and instruments Panels Relays Cabinets or cubicles Synchronous condensers and cooling towers (including associated pumps and auxiliary equipment) Transformer truck and R.R. track system Voltage regulators Also include other maintenance labor such as: Repainting station steel or pole structure and equipment (other than transformers, circuit breakers, buses and disconnects) Repairing or replacing "Danger" signs Repairing or replacing relays Repairing station tools, testing hot sticks, etc. Repairing station trailers Replacing cable or duct of less than a continuous circuit. Material: Bolts Fence material Minor replacement parts for equipment listed in this account Paint and brushes Refills for fire extinguishers 15 lbs. and over (dry) and 2-1/2 gallon and over (liquid) Tape Small portable tools, testing equipment, safety equipment, first aid kits and medical supplies Splicing material Gas for synchronous condensers All Other: Rental paid for emergency use of transmission power transformers. Rental paid for use of portable stations. State and city licenses for trailers used regularly for transporting transmission station equipment.
738	5710000	Maintenance of Overhead Lines	This account shall include the cost of labor, material used and expenses incurred in maintenance work on transmission overhead lines, the book cost of which is included in Accounts 354, Towers and Fixtures, 355, Poles and Fixtures, and 356, Overhead Conductors and Devices not elsewhere provided for in the other subdivisions of Account 5710000, Maintenance of Overhead Lines. Also include herein the cost of labor, material use and expenses incurred in the maintenance of roads and trails, the book cost of which is includible in Account 359, Roads and Trails and the maintenance work on publicly owned roads and trails when done by the utility at its own expense. Payroll Labor: Clearing brush from trails. Clearing drainage ditches. 3. Regrading roads. Removing snow from roads and trails. Repairing surface of roads. Repairing bridges and culverts. Repairing steps (stiles) over fences on trails. Repairing access and country roads to reach point of trouble. Material: Cement Gravel Lumber Small, portable tools, testing equipment, safety equipment, first aid kits and medical supplies.

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Line No.	G/L Account	Account Description	Additional Description
739	5720000	Maint of Underground Lines	underground lines, including costs of the entire entrance to a substation (excluding any above ground support structure) and the first pot head of termination on a tower or pole outside the station, the cost of which is includible in Account 357, Underground Conduit and Account 358, Underground Conductors and Devices. Payroll Labor: 1. Cleaning ducts, manholes and sewer connections. 2. Excavating, back filling, hauling dirt, brick, gravel, etc. and repairing pavement due to maintenance of underground lines. 3. Inspecting and testing for faults and performance after maintenance. 4. Investigating extent of damage to determine what maintenance is necessary as a result of flood, storm or excavation by others, etc. 5. Minor alterations of handholds, manholes or vaults. 6. Moving of changing position of conduit. 7. Protection at openings for maintenance work on underground lines. 8. Refastening, repairing or moving racks and ladders in vaults. 9. Refireproofing cables and repairing supports. 10. Repainting conduit, ducts, etc. 11. Repairing and cleaning tools used on underground transmission line maintenance. 12. Repairing cable bonding system. 13. Repairing electrolysis preventive devices for cables. 14. Repair grounds. 15. Repairing line testing equipment. 16. Replacing pavement, curbs and walks after maintenance work. 17. Repairing property of others damaged (planned or unavoidable) while performing maintenance work. 18. Repairing of moving junction boxes and pot heads. 19. Replacing pot head compound. 20. Retaping, repairing, replacing (less than a retirement unit), reconnecting splicing, repainting and changing location of any of the following: A. Conductor (buried) section of less than 600 feet. B. Conductors (in conduit) less than circuit between two manholes or between manhole and pole. C. Conductor (submarine) less than submerged length of cable between terminal chambers or manholes. 21. Sampling, testing, changing, purifying and replenishing insulating oil. 22. Special testing and checking of underground lines to locate trouble known to exist. 23. Transferring loads, switching and reconnecting circuits and equipment for maintenance purposes. Material: 1. Representative list of principal items: Conduit and ducts (concrete, brick, title, iron, plastic or fiber pipe, etc.) (A section of conduit between two manholes or between a manhole and a pole is a retirement unit.) Manholes and vaults (a complete manhole, splicing chamber or cable vault is a retirement unit.) Cable racks Covers Foundation Frame Grating Hangers and other manhole accessories Hatchways Ladders Lighting system Sewer connections, drains, traps, valves, etc. Sump pumps Ventilating equipment* * A complete installation at one location is a retirement unit. Risers Conductors and Devices Bus bars Conductor (all types-buried, submarine or in underground conduit)* Cable splices and terminations Circuit breakers** Connectors
740	5730000	Maint of Misc Trnsmssion Plt	This account shall include the cost of labor, materials used and expenses incurred in the maintenance of owned or leased plant which is assignable to transmission operations and is not provided for elsewhere. Payroll Labor: 1. Cleaning, inspecting, repairing and repainting transmission line department tools and work equipment, such as: Air compressorsDerricksSurveying equipment Hoists Power sawsWelding apparatus Pumps Vises Safety platforms 2. Repairing office furniture and equipment used by the Transmission Department is stations or offices. Material: Small, portable tools, testing equipment, safety equipment, first aid kits and medical supplies.
741	5757002	SPP Admin-MAM&SC	SPP administrative service fees for market administration, monitoring and compliance services. This account shall include the costs billed to the transmission owner, load serving entity or generator for market administration, monitoring and compliance services.
742	5800000	Oper Supervision & Engineering	This account shall include the applicable portion of the cost of labor and expenses incurred in the general supervision, direction, planning, coordination, instruction and training in connection with the operation of the distribution system. It shall include the portion of services of personnel such as the Region and District Supervisors, Engineers, Superintendents, General Foremen, Consultants and Secretarial work for this group. Include herein the general supervision and direction of work as it relates to operation only, but not the actual performance of such work or the immediate and direct supervision chargeable to other accounts appropriate for the work performed. In the case of fixed classification employees, such percentage of their time applicable, as determined by periodic time studies, shall be classified to the intra-company overhead work orders established under Account 1070000, Construction Work in Progress and sub account 1080000, Retirement of Electric Plant in Service under Account 108000, Accumulated Provision for Depreciation of Electric Plant in Service. Exclude from this account and include in Account 5860001, Meter Expenses - Supervision, the general supervision of the Meter Department activities pertaining to operation. Also exclude general clerical and stenographic work includible in Account 5860002, Meter Expenses - Office Salaries and Expenses and 5880000, Miscellaneous Distribution Expenses - All Other as appropriate. Note: For billings involving work on the property of others, credit this account with 2/3 of the overheads added to the billings. (The remaining 1/3 of the overheads is to be credited to Account 9200003, Administrative and General Salaries Transferred.)

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Line No.	G/L Account	Account Description	Additional Description
743	5810000	Load Dispatching	This account shall include the cost of labor, materials used and expenses incurred in load dispatching operations pertaining to the distribution of electricity. Include herein the applicable portion of duties and responsibilities performed by supervisory personnel of the System Operating Department related to the Distribution function. If load dispatchers and their assistants are stationed at a distribution station and a part of their time is devoted to the operation of that station, their time shall be apportioned between this account and the appropriate distribution station account on and equitable basis. Payroll Labor: 1. Arranging and controlling clearances for construction, maintenance, test and emergency purposes. 2. Assisting in all new practices and procedures for improvement of dispatching operations related to the distribution function. 3. Assisting with educational program of job training for system operators and load dispatchers. 4. Checking primary bus voltage at various points on the system. 5. Checking line loading and reactive flows. 6. Checking existing operating practices and procedures for any changes or revisions. 7. Checking switching diagrams on existing and new jobs for operating features. 8. Checking switching diagrams for expansion of facilities, distribution stations and lines before actual operation. 9. Continuous checks on daily, weekly and monthly basis of district and system peaks. 10. Controlling system voltages. 11. Directing switching. 12. Explaining and checking operating manual procedures with operating personnel over the system. 13. General operation of distribution lines and distribution stations over the system. Working closely with supervisor, operators and dispatchers. 14. Obtaining reports on weather and special events. 15. Preparing, Checking, Reviewing or Supervising: A. Load data reports, load forecasts, etc. B. Operating diagrams and procedures, switching diagrams, etc. C. Work on incremental plant studies. 16. Reviewing operating orders and procedures for operating manual. 17. Supervising on-job training of office and field trainees. 18. Supervising operation and switching on major outage. Outside Services: 1. Charge by associated companies. 2. Cost of Weather and Special Events Reports (portion) Material: Forms and supplies used in the preparation of distribution dispatching records and reports. All Other: Communication - Leased telephone circuits for use by system operating department the function of which are: A. Supervisory control - Observation of conditions at remote generating plant or substation and control of functions at that point. B. Alarms - One way signal for indication of abnormal
744	5820000	Station Expenses	stations, the book cost of which is included in Account 362, Station Equipment. Payroll Labor: 1. Adjusting station equipment where such adjustment primarily affects performance, such as regulating the flow of a coolant, changing voltage of regulator or changing taps or connections on station transformers. Also inspecting, testing and calibrating station equipment for the purpose of checking its performance. Note: When the foregoing work requires extensive disassembling and reassembling of equipment, or is done to prevent or correct trouble or failure, or is incidental to maintenance work, it should not be charged to this account but to the appropriate maintenance account. 2. Clearing snow or ice from distribution station walks, roads or parking areas. 3. Cleaning grounds and station buildings, including janitor service. 4. General inspection of distribution stations. 5. Guarding and patrolling station equipment and yard. 6. Inspecting and servicing storage batteries. 7. Inspecting, cleaning and keeping record to tools used around station. 8. Inspecting all fire extinguishers for distribution stations and refilling those of 1 quart size or smaller. Note: Refilling fire extinguishers of larger than 1 quart size and the cost of chemical shall be charged to the appropriate maintenance account. 9. Mowing grass, weeding, attending flowers and shrubbery. 10. Oiling and greasing equipment when done as a part of routine operation. 11. Operating switching and other station equipment. 12. Preparing station log, record and special reports associated with the operation of distribution station equipment. 13. Reading station meters (other than customer metering). 14. Removing foreign objects from distribution station equipment such as kites, tree branches, etc., when done incidental to regular operating duties. 15. Replacing burned out lamps. 16. Reporting load conditions or requirements as requested. 17. Resetting and winding time clocks for station lights. 18. Routine checking of load or voltage. 19. Routine checking, inspecting and testing at distribution station for radio and television interference. 20. Sampling and testing lubricants or hydraulic control oils. Sampling and testing insulating oils should be charged to maintenance. 21. Switching to clear lines for repair or inspection. (Time of diversified employees shall be charged to Account 5930004, Maintenance of Overhead Conductors and Devices.) 22. Testing public telephone at distribution station. 23. Watch engineer at distribution station. 24. Calibrate relays, potential devices. 25. Check automatic reclosing of oil and air circuit breakers with respect to performance of relays. 26. Check automatic operation of motor-operated switches with respect to performance of relays. 27. Check tripping of oil and air circuit breakers. 28. Clean and adjust relays, relay parts and devices. 29. Inspect station control wiring system for

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Line No.	G/L Account	Account Description	Additional Description
745	5830000	Overhead Line Expenses	distribution lines not provided for in the other subdivisions of Account 5830000, Overhead Line Expenses. The following should also be included herein: The general inspecting, testing and patrolling of distribution overhead primaries, secondaries and services when done on a routine basis for the purpose of checking the condition, efficiency and performance of property and equipment, where no trouble is know to exist or is anticipated and only relatively minor repairs and adjustments, if any, are found to be necessary. Patrolling to locate and clear know trouble should be charged to the maintenance account appropriate for the equipment. Testing and inspecting line oil switches, line reclosers, sectionalizers, and line capacitor banks (switched and fixed) on a routine basis for the purpose of checking the condition and performance where no trouble is know to exist and only relatively minor repairs and adjustments, if any, are found to be necessary. Testing and inspecting this equipment in connection with a planned maintenance program or testing and inspecting to locate and clear trouble when know to exist or to determine the extent of damage and what repairs are necessary, should be charged to the maintenance account appropriate for the equipment, Account 5930005, Maintenance of Line Reclosers and Sectionalizers. Metering loads and voltages, or computing loads, power factors, voltages and fault currents from correlated data, on distribution overhead primaries, secondaries and service when done for the purpose of checking the condition, efficiency and performance of portions of the distribution system and equipment where no line equipment trouble is known to exist, or is anticipated, and only relatively minor repairs and adjustments, if any, are found to be necessary. Payroll Labor: Checking sleet conditions on distribution lines. General inspecting and patrolling to observe the condition and performance of poles, conductors and devices on overhead distribution lines. Removing foreign objects such as kites, branches and birds from overhead distribution lines and services incidental to routine patrolling. Repairing fences or other property damaged by patrolmen on routine patrol. Routine scheduled patrols. Checking circuit continuity and making insulation tests. Checking operation sequences, time delays, time-current characteristics. Inspecting tank working parts, contacts, and control for signs of deterioration, flashover, sludge, etc. Reading counters. Removing and reinstalling oil switches, line reclosers and sectionalizers or otherwise by-passing or isolating this equipment for inspection. Sampling oil for dielectric test. Tabulating records and compiling reports relating to the foregoing work when done by employees performing the testing and inspecting. Inspecting all fixed and switched capacitor banks. Note: The following pertain to labor for work as covered by item 3 in the preceding test of this account. Changing tapes or charts on testing equipment and reading and recording data shown by such
746	5840000	Underground Line Expenses	This account shall include the cost of labor, materials used and expenses incurred in the operation of underground distribution lines. Also include the immediate and direct supervision of such work. Payroll Labor: 1. Checking operating performance and condition of underground installations after excavation by others involving gas, water or heating mains. 2. Checking load on transformers, cables and customers' service. 3. Clearing snow or water from transformer vaults and manholes. 4. Inspecting and adjusting line testing equipment. 5. Making electrolysis surveys. 6. Making load tests and voltage surveys on underground distribution system for general operating conditions. 7. Measuring ground resistance on underground distribution system. 8. Routine checking and testing of switches, potheads, cables and accessories. 9. Routine inspecting and testing of company underground distribution lines to prevent radio and television interference (not customer complaint). 10. Routine inspection of subway ducts, manholes, sewer connections, wire connections and cable splices. 11. Locating Company's underground distribution facilities at request of contractor or customer. Material: 1. Instruments charts. 2. Small, portable tools, testing equipment, safety equipment, first aid kits and medical

Line No.	G/L Account	Account Description	Additional Description
747	5850000	Street Lighting & Signal Sys E	This account shall include the cost of labor, materials used and expenses incurred in the operation of the overhead and underground street lighting and signal systems, including traffic, fire and police signal systems when owned or operated by the company. Include herein renewing lamps and washing globes and reflectors on the street lighting system. Also include herein maintenance of street lighting and signal systems owned by the customer, when work is done regularly as a part of the service contract. Note: Both operation and maintenance expense in connection with street lighting and signal systems owned by the customer, when service contract does not provide for such work, shall be charged to Account 5870000, Customer Installation Expenses - All Other. Payroll Labor: 1. Inspecting and attending time clocks. 2. Inspecting circuits, ducts, manholes, etc., after building wrecking, moving or steam shovel operations. 3. Inspecting and testing street lighting panel at generating station. 4. Making voltage tests. 5. Opening or closing street lighting cutouts. 6. Removing foreign objects from street lighting circuits such as kites, branches, etc. when not in connection with maintenance. 7. Routine patrolling, inspecting and testing of street lighting circuits, transformers and accessories. 8. Routine testing and adjusting of photoelectric controls used for street lighting. 9. Testing and inspecting grounds on circuit and transformers. 10. Trimming branches from trees to provide better lighting on walks when done incidental to routine patrolling and inspecting of lighting circuits. 11. Renewing burned out or defective lamps. 12. Washing street lighting globes and reflectors. Materials: 1. Incandescent, mercury vapor and fluorescent lamps and cleaning supplies. 2. Small,, portable tools, testing equipment, safety equipment, first aid kits and medical supplies 3. Cards and report forms. 4. Film cutouts. 5. Lamp socket pullers.
748	5860000	Meter Expenses	This account shall include only the cost of labor, materials used and expenses incurred in operations related to customer meters and associated equipment not elsewhere provided for in the other subdivisions of Account 5860000, Meter Expenses. Payroll Labor: Initial field investigation for defective demand meters. (Time spent on corrective measures is to be classified to the account appropriate for the work performed). Material: Meter seals and sealing presses. Small, portable tools, testing equipment, safety equipment, first aid kits and medical supplies.
749	5870000	Customer Installations Exp	This account shall include the cost of labor, materials used and expenses incurred in work on customers' premises other than that provided for in subdivisions of Account 5860000, Meter Expenses and in other subdivisions of this Account 5870000, Customer Installation Expenses. Include herein operation and maintenance of street lighting and signal systems owned by the customer, when service contract does not provide for such work. Note: Operation and maintenance of street lighting and signal systems owned by the customer, when work is done regularly as a part of the service contract, shall be charged to Account 5850000, Street Lighting and Signal System Expenses. Payroll Labor: Changing customers' equipment due to change from direct to alternating current. Changing customers' wiring or equipment due to voltage change. Changing voltage of customers' equipment. Inductive, coordination testing of customers' equipment for noise in telephone lines. Inspecting customer-owned line. Inspecting customers' installations (inside work) on dealers' sales. Inspecting customers' installations for code compliance. Installing and removing equipment leased or loaned to customer when chargeable to Account 372, Leased Property on Customers' Premises. Installing sanding machine service and box. Investigating fire on customers' premises with or at request of the fire department. Investigating, setting, removing and reading check meters on unauthorized use of electric energy. Also disconnecting service if occasioned by current diversion. Investigating and reporting to Customers Services Department on customer-owned station, line or other equipment. Investigating use of energy on inactive meter. Layout of work to be done on customers' premises. Locating and clearing grounds on customers' wiring. Marking customer-owned equipment as to ownership, etc. Measuring ground resistance on customers' premises. Opening and closing customers' transformer cutouts in order that customer can make repairs to his equipment. Repairing customers' line switch. Repairing street lighting standard, or fixtures, maintained but not owned, by company where no billing is involved. Repairing service between curb line and customers' line switch (customers' portion). Reporting unauthorized use of current. Testing voltage on customer-owned line or equipment. Work performed on load side of meter for which no charge is made but which tends to improve our service. Replacing burned out or defective lamps and low voltage fuses. Routine inspecting and testing of lighting units. Washing globes. Disconnecting dusk-to-dawn lighting when the premises are vacated. "No Power" service calls. Outside Services: Include charges by associated companies. Material: Materials and equipment such as motors, switches, wire, etc., (when cost is borne by company) installed in connection with changes in voltage or from DC to AC. Small, portable tools, testing equipment, safety equipment, first aid kits and medical supplies. Cleaning supplies. Lamp and fuse renewals - "No Power" service calls. All Other: Reward, or bonus, paid employee for

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			This account shall include the cost of labor, materials used and expenses incurred in distribution office operations not elsewhere provided for. Payroll Labor: Answering phone in service dispatcher's office, receiving trouble calls and preparing investigation orders. Standby and answering telephone for trouble calls during storm. Time of radio dispatcher receiving customer complaints. Time of janitor cleaning distribution offices. Time of driver of auto delivering and picking up mail, reports, materials and supplies relating to the distribution operation. Time of right-of-way agent not assignable to a specific work order and when investigating and settling disputes pertaining to existing lines. Material: Cleaning supplies Salt for water softening purposes. Small, portable tools, testing equipment, safety equipment, first aid kits and medical supplies. Office supplies. Metal signs on right-of-way. All Other: Communication service for distribution stations and engineering offices. Leased telephone circuits and lines Postage applicable to distribution operations Rentals paid under lease agreement for mobile radios and communication equipment used by distribution personnel. Personal property taxes. Water service rental Research and development expenses. Note: Include herein labor and expense in connection with strike preparation applicable to the distribution function.
750	5880000	Miscellaneous Distribution Exp	This account includes the cost of individual business and professional memberships; see Account 4265004 for social memberships and related expenses and see Account 9302000 for corporate memberships such as for industry dues, e.g., EEI.
751	5890001	Rents - Nonassociated	This account shall include rents of nonassociated companies property of others used, occupied, or operated in connection with the distribution system. 1. Rental paid for pole attachments. 2. Rental of buildings for distribution system operations. 3. Rentals for highway or railroad crossings for distribution lines. 4. Charges by telephone or other utility companies for increased height in poles or other facility changes requested by the electric operating company as necessary for joint company use. (See Note C) 5. Rental of underground ducts for underground conductors. Note A: Rents paid for property devoted to operations for which clearing accounts are used shall be charged to the appropriate clearing accounts. Note B: Rents, which are irregular or infrequent, paid for the use of equipment on specific construction, retirement, or maintenance projects, shall be charged to the accounts appropriate for the work performed. Note C: When facility changes are caused by highway relocation, changes shall be initially recorded in the appropriate Other Work in Progress work order for subsequent billing to the State Highway Department.
752	5890002	Rents - Associated	This account shall include rents of associated companies property of others used, occupied, or operated in connection with the distribution system. 1. Rental paid for pole attachments. 2. Rental of buildings for distribution system operations. 3. Rentals for highway or railroad crossings for distribution lines. 4. Charges by telephone or other utility companies for increased height in poles or other facility changes requested by the electric operating company as necessary for joint company use. (See Note C) 5. Rental of underground ducts for underground conductors. Note A: Rents paid for property devoted to operations for which clearing accounts are used shall be charged to the appropriate clearing accounts. Note B: Rents, which are irregular or infrequent, paid for the use of equipment on specific construction, retirement, or maintenance projects, shall be charged to the accounts appropriate for the work performed. Note C: When facility changes are caused by highway relocation, changes shall be initially recorded in the appropriate Other Work in Progress work order for subsequent billing to the State
753	5900000	Maint Supv & Engineering	This account shall include the applicable portion of the cost of labor and expenses incurred in the general supervision, direction, planning, coordination, instruction and training in connection with the maintenance of the distribution system. It shall include the portion of services of personnel such as the Region and District Supervisor, Engineers, Superintendents, General Foremen, Consultants and Secretarial work for this group. Include herein the general supervision and direction of work as it relates to maintenance only, but not the actual performance of such work or the immediate and direct supervision chargeable to other accounts appropriate for the work performed. Exclude from this account and include in Account 5970000, Maintenance of Meters - Supervision, the general supervision of the Meter Department activities pertaining to maintenance. Also exclude general clerical and stenographic work includible in Accounts 5860002, Meter Expenses - Office Salaries and Expenses and 5880000, Miscellaneous Distribution Expenses - All Other as appropriate. Note: For billings involving relocation of distribution facilities, the portion of the overheads added to the billings which relate to operating expenses is to be credited 2/3 to this account and 1/3 to Account 9200003, Administrative and General Salaries Transferred. The remaining portion of the total overheads included in the billings is to be credited to Account 1080000, Retirement of

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Line No.	G/L Account	Account Description	Additional Description
754	5910000	Maintenance of Structures	This account shall include the cost of labor, material used and expenses incurred in the maintenance, other than painting, of distribution structures, the book cost of which is includible in Account 361, Structures and Improvements. Payroll Labor: Maintenance labor on the following equipment: Company-owned railroad siding. Danger signs on fence or buildings. Drinking water system wells, pumps, piping, etc. Fence enclosing station property. Heating, lighting, ventilating and fire protection systems for station buildings or cottages. Retaining walls. Station and line crew shops. Station buildings. Station operator's cottage. Walks, drives, parking areas. Yard and station drainage. Yard lighting (not for equipment). Also include other maintenance labor such as: Ditching to maintain drainages. Making and installing markers for station plot boundary. Refusing station heaters. Repairing plumbing facilities, drainages and sewer system. Repairing tools used on maintenance. Replacing gravel on station yard or driveway. Resurfacing yard, replacing shrubbery, fertilizing grass and chemical killing of weeds. Special work to recondition yards and buildings after landslides or severe storms. Material: Lumber, gravel, plumbing supplies. Small, portable tools, testing equipment, safety equipment, first aid kits and medical supplies.
755	5920000	Maint of Station Equipment	This account shall include the cost of labor, material used and expenses incurred in maintenance of equipment in distribution stations other than that provided for in the other subdivisions of Account 5920000, Maintenance of Station Equipment. Payroll Labor: 1. Batteries, charger and transformer (control equipment). 2. Capacitor banks. Conduits and cables located on station property. Conversion equipment, frequency changers, motor generator sets, rectifiers, synchronous condenser. Dead ending units on incoming and outgoing lines. Equipment steel, structure. Fences isolating equipment. Fire extinguishing system for protection of equipment. Hoists, cranes and motors. Hot sticks and rubber protective equipment for maintenance work (includes testing and storing). Instrument transformers. Lightning arresters. Meters and instruments (exclude billing meters). Platforms and railings appurtenant to equipment. Reclosers. Also include other maintenance labor such as: Repairing or replacing relays. Changing air filter pads in condenser. Moving drying ovens to and from locations. Repainting station equipment (other than transformers, regulators, circuit breakers, buses and disconnects). Repairing station shop equipment. Repairing station trailers. Materials: Bolts Fence material Minor replacement parts for equipment listed in this account. Paint and brushes Refills for fire extinguishers 15 lbs. and over (dry) and 2-1/2 gallon and over (liquid). Tape Small, portable tools, testing equipment, safety equipment, first aid kits and medical supplies. All Other: State and City licenses for trailers used regularly for transporting distribution station equipment. Note: Excludes costs of the entire entrance to the Station (including any above ground support structures) and all underground conduit, conductors, and devices to and including the first pothead or termination on
756	5930000	Maintenance of Overhead Lines	This account shall include only the cost of labor, material used and expenses incurred in maintenance work on distribution overhead lines, the book cost of which is includible in Accounts 364, Poles, Towers and Fixtures and 365, Overhead Conductors and Devices, not elsewhere provided for in the other subdivisions of Account 5930000, Maintenance of Overhead Lines.
757	5930007	Mnt O/H Line Reliability-Def	To defer incremental distribution reliability O&M expenses for future recovery through Virginia Environmental & Reliability cost recovery mechanism in account 593 normally as a credit.
758	5940000	Maint of Underground Lines	This account shall include the cost of labor, materials used and expenses incurred in the maintenance of underground distribution line facilities, the book cost of which is includible in Account 366, Underground Conduit, Account 367, Underground Conductors and Devices, and Account 369, Services.

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Line No.	G/L Account	Account Description	Additional Description
759	5950000	Maint of Lne Trnf,Rglators&Dvi	line transformers and devices, the book cost of which is includible in Account 368, Line Transformers. Also include in this account the maintenance of distribution line voltage regulators, capacitors, network protectors and devices, the book cost of which is also in Account 368, Line Transformers. Payroll Labor: 1. Changing location of same transformer on same pole. 2. Crating line transformers for shipment to be repaired. 3. Inspecting line transformers devices, cutouts and lightning arresters to determine what repairs are needed when trouble is known to exist. (If replacements of retirement units are made, charges shall be through retirement and construction.) 4. Repainting line transformers. 5. Replacing defective arresters and cutouts. 6. Refusing line transformer cutouts (not refusing cutouts used for line sectionalizing). 7. Rewinding and changing taps on line transformers. 8. Repairing cutouts and arresters. 9. Renumbering line transformers. 10. Repairing company-owned line transformers and devices to correct radio and television interference. 11. Replacing thermometers in line transformers. 12. Sampling, testing, changing, purifying and replacing insulating oil. 13. Taking line transformers to shop for repairs. 14. Testing and inspecting line transformers removed from service due to failure. 15. Transferring same line transformer to new pole at same location or from one pole location to another pole location. 16. Checking and replacing contacts. 17. Checking and replacing insulating oil. 18. Inspecting voltage regulators to determine what repairs are needed when trouble is known to exist. 19. Repainting voltage regulator tanks. 20. Relocating voltage regulators, arresters, etc., at the same pole location. 21. Replacing defective parts. 22. Maintenance of capacitor racks and associated equipment. 23. Maintenance of capacitor control devices. 24. Maintenance of capacitors. 25. Maintenance of network protectors. 26. Replacing capacitor fuses. 27. Replacing distribution transformer risers. Outside Services: Include herein charges by the manufacturer for repairs to line transformers and devices for work performed in the factory or elsewhere. Material: 1. Arresters 2. Cutouts 3. Insulating oil 4. Mounting plates used in reinstallation of older transformers. 5. Paint 6. Small, portable tools, testing equipment, safety equipment, first aid kits and medical supplies. Note: The replacement of core and oil in kind in line transformers shall not be charged to this account. DEFINITION OF A LINE TRANSFORMER The following definition is taken from AEP System Accounting Bulletin No. 19, Revised May 1, 1972. A. A transformer having a high voltage winding of not less than 2,400 volts* and not more than 34.5 Grd. Y/20 kv (three phase, or single phase with single bushing) or 20/34.5 Y kv (single phase with two bushings) is to be considered as a Line Transformer and classified to Account 368, Line Transformers at time of purchase
760	5960000	Maint of Strt Lghtng & Sgnal S	This account shall include the cost of labor, materials used and expenses incurred in maintenance of plant, the book cost of which is includible in account 373, Street Lighting and Signal Systems.
761	5970000	Maintenance of Meters	This account shall include the cost of labor, materials used and expenses incurred in the maintenance of meters, meter devices and instrument transformers used in measuring energy delivered to customers and also those used in measuring energy used by the company, the book cost of which is includible in Account 370, Meters. It shall also include the maintenance of meter testing equipment, the book cost of which is includible in Account 395, Laboratory Equipment. Payroll Labor: Cleaning, inspecting and repairing small and special tools used in maintenance of meters. Cleaning, inspecting, repairing and adjusting meter laboratory testing equipment. Packing and sending meters away for repairs. Repairing, cleaning and repainting meters. Renumbering meters. Repairing or replacing meter bases and sockets (mounting devices). Reconditioning, inspecting and replacing jewels, top bearings and other parts. Relocating meters, devices, mountings and accessories at same location. Testing and renewing oil in instrument transformers used for customer metering only. Outside Services: Include herein charges by the manufacturer for repairs to meters and metering equipment for work performed in the factory or elsewhere. Material: Insulating oil Meter jewels and top bearings Padlocks for meter boxes Paint Pilot lights Small, portable tools, testing equipment, safety equipment, first aid kits and medical supplies. Tape Other miscellaneous parts and supplies. Note: Labor and expenses incurred in modernization of old meters should not be charged directly to this account but to the work order established for that purpose.

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Line No.	G/L Account	Account Description	Additional Description
762	5980000	Maint of Misc Distribution Plt	This account shall include the cost of labor, material used and expenses incurred in maintenance of plant, the book cost of which is includible in Account 371, Installations on Customers' Premises, 372. Leased Property on Customers' Premises and any other plant the maintenance of which is assignable to the distribution function and is not provided for elsewhere. Include herein the cost of maintenance of equipment installed on the customer's side if the meter when the company incurs such cost, retains title to the equipment and assumes responsibility for maintenance. This includes such equipment as electric motors and transformers leased or loaned to customers, but not including property held for sale. The cost (when borne by the company) of setting, connecting, resetting and removal of this equipment should be charged to this account. Any amounts billed to the customer for the cost of work performed in connection with the above shall be credited to this account. Rents billed to the customer for the use of the equipment shall be credited to Account 4540000, Rent from Electric Property, or Account 4540002, Rent From Electric Property From Non-Associated Companies. Payroll Labor: Cleaning, inspecting, repairing and repainting Distribution Department tools and work equipment such as: Air compressors Derricks Hoists Power saws Pumps Safety platforms Surveying equipment Vises Welding equipment 2. Inspecting, cleaning and repairing equipment installed on the customer's side of the meter (company-owned and maintained). 3. Repairing office furniture and equipment used by the Distribution Department in stations or offices. 4. Repairing equipment on customers' premises leased or loaned to customer and classified in Account 372, Leased Property on Customers' Premises. Material: 1. Replacement parts, wire, and miscellaneous supplies. 2. Small, portable tools, testing equipment, safety equipment, first aid kits and medical supplies. 3. Photoelectric controls - replacements of individual controls installed as part of a lighting unit. Note: Heavy-duty switches that control a series of lights should follow retirement and recapitalization accounting.
763	9010000	Supervision - Customer Accts	This account shall include the cost of labor and expenses of Customer Accounting personnel engaged in general supervision, directing, planning, coordinating, instructing or training applicable to customer accounting and collecting activities. It shall exclude the salaries and expenses of personnel engaged in the immediate or direct supervision of such activities, which should be charged to the account(s) appropriate for the work performed. Payroll Labor: 1. Coordinating work in customer accounting department with other departments. 2. Establishing organization setup of the department and executing changes therein. 3. Formulating and reviewing routines of the department and executing changes therein. 4. Periodic auditing of: A. Cash drawers B. Petty cash funds and related records C. Receipt books Note: Does not include audits by Service Corporation Auditors. 5. Periodic checking of collection agents. 6. Preparing and reviewing operating budgets for the department. 7. Preparing operating instructions for the department. 8. Reviewing and analyzing operating costs. 9. Reviewing and approving: A. Monthly sub-office reports B. Revenue adjustments and similar entries C. Time reports D. Expense accounts E. Payroll records for customer accounting employees. 10. Verification of scrap sales. 11. Secretarial work for general supervisory personnel, but not general clerical and stenographic work, all of which is chargeable to other accounts. Material: 1. Business calling cards for Customer Accounting Supervisors.
764	9020000	Meter Reading Expenses	This account shall include the cost of labor, materials used and expenses incurred in connection with reading customers' meters not chargeable to other accounts. Payroll Labor: Assembling meter reading documents into meter reading routes. Assembling meter reading documents into cycle order for shipment to centralized customer accounting. Checking meter reading documents and charts. Estimating meter readings for accounts where regular scheduled meter readings were not obtained by meter readers. Maintaining record of customers' keys. Rerouting and refolioing of routes and accounts in the field. Rerouting and refolioing by office personnel. Material: Meter reading documents. Meter reader report cards. Meter reader instruction cards. Supplemental instruction cards. Multi-bar Meter Seals - used by meter readers in sealing demand meters after the old seal is broken to reset the maximum hand at the time of regular meter readings. This account includes the cost of individual business and professional memberships; see Account 4265004 for social memberships and related expenses and see Account 9302000 for corporate memberships such as for industry dues, e.g., EEI.
765	9020001	Customer Card Reading	This account shall include the cost of labor, material used and expenses incurred in connection with customer card reading. Payroll Labor: 1. Addressing and mailing customer reading cards. 2. Estimating meter readings of meters for which cards are not returned by customer or in case of incorrect reading by customer. 3. Transferring readings from customers' cards to OCR documents. 4. Maintaining record of customer reading cards mailed and returned for analysis. Material: Customer reading cards - cost. All Other: 1. Postage on reading cards mailed to customer. 2. Postage on reading cards mailed by customer

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766	9020002	Meter Reading - Regular	This account shall include the cost of labor, material used and expenses incurred in obtaining regular readings of customers' meters, other than large power meters, by employees engaged in reading meters. Payroll Labor: 1. Verify that present readings are within hi-low limits shown on the meter reading documents. 2. Investigation by meter reader of active account where premises are found to be unoccupied. 3. Investigation by meter reader of registration on inactive account. 4. Reading meter on customers' premises at regular scheduled reading dates. 5. Travel time of meter readers to starting location and from last location to office. 6. Observe and report defective and hazardous metering or service facilities and other hazardous conditions when performed incidental to reading meters. 7. Record information on meter reading documents for various surveys when directed, such as, accounts with meter pedestals, etc., when done in connection with regular meter reading. Material: Meter readers' uniforms, protective equipment, boxes, flashlights, etc. Note: Time of regular meter readers, reading large Commercial and Industrial meters should be charged to Account 9020003, Reading Large Power Meters.
767	9020003	Meter Reading - Large Power	This account shall include the cost of labor, materials used and expenses incurred in reading large power meters. Payroll Labor: 1. Changing and collecting meter charts used for billing purposes. 2. Inspecting time clocks, checking seals, etc., when performed by meter readers and the work represents a minor activity incidental to regular meter reading routine. 3. Reading large power meters. 4. Recording readings on specified forms. 5. Travel time of meter readers to starting location and from last location to office Material: Meter reading charts and
768	9020004	Read-In & Read-Out Meters	This account shall include the labor and expenses incurred in obtaining read-in and read-out readings in connection with initiating or terminating service. This account shall exclude the cost of all work, including the obtaining of meter readings, in connection with installing, removing, disconnecting, connecting, etc., meters and services. See Note. Payroll Labor: Obtaining read-in and read-out readings as per the foregoing. Note: The cost of installing, removing, disconnecting, connecting, etc., meters, and the cost of obtaining meter readings incidental thereto, shall be charged to Accounts as follows: A. Initiating or terminating service at customers' request, and B. Unauthorized use of energy - Charge to 5860007 - Disconnecting and Reconnecting Meters - Initiating or Terminating Service. C. Nonpayment of account - Charge to 9030006 - Credit and Other Collection Activities, and 9030007 - Collectors.
769	9030000	Cust Records & Collection Exp	This account shall include the cost of labor, materials used and expenses incurred in the accounting offices, centralized customer accounting and data processing center in connection with customer records. Payroll Labor: Compiling advances for construction allowances. Compiling franchise requirement report. Compiling request for transfers of balances. Compiling adjustments and posting to billing register and other local office records. Compiling and typing report of materials loaned or rented. Filing collection reports when done by other than cashiers. Maintaining records of advances for construction. Verifying meter constant report. Verifying employee discount records. Checking and initiating action on Cycle 22 items and other transfer items. Preparing refunds of credit balances for final billed accounts.
770	9030001	Customer Orders & Inquiries	This account shall include the cost of labor, materials used, and expenses incurred by employees engaged in work on customers' applications, contracts, orders, complaints and inquires, but excluding the cost of carrying out such orders, which is chargeable to the accounts appropriate for the work called for by such orders. Payroll Labor: 1. Accepting requests from customers to read, install, connect and disconnect meters. 2. Analyzing disputed accounts. 3. Compiling duplicate bills for customers. 4. Compiling, checking and filing investigation orders when done by Customer Accounting personnel. 5. Compiling water heater verification forms. 6. Handling customers' complaints and inquires in the office. 7. Posting, maintaining, and checking service location record file. 8. Preparing, filing and checking service orders. 9. Analyzing long and short form memos. 10. Handling Equal Payment Plan accounts, when performed by Customer Accounting personnel. 11. Assigning account numbers to new accounts. Material: 1. Duplicate bill forms. 2. Forms such as, applications, contracts, investigation orders and service orders.
771	9030002	Manual Billing	This account shall include the cost of labor, materials used, and expenses incurred in manual billing of large commercial and industrial accounts, also maintaining and checking hand-billed ledgers. Payroll Labor: 1. Checking hand-billed accounts after billing. 2. Computing bills. 3. Compiling bills. 4. Writing customer meter sheets. Material: Ledger sheets, bills, billing record forms and supplies not applicable to other accounts.
772	9030003	Postage - Customer Bills	This account shall be charged with the cost of postage on customers' electric bills.

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
773	9030004	Cashiering	This account shall include the labor and expenses of employee engaged in receiving and handling payments of customers' bills in company offices and the preparation of cash reports in connection therewith. Payroll Labor: 1. Accepting payments of and receipting for all bills. 2. Balancing cash drawer, sorting cashier coupons, running balance tapes, and preparing batch tickets. 3. Compiling and delivering bank deposits. 4. Compiling and typing daily cash reports. 5. Filing collection reports - when done by cashier. 6. Opening, sorting and balancing mail and night depository receipts. 7. Recording cashiers' and collectors' overages and shortages. 8. Verifying collection reports. Outside Services: Armored car service Material: 1. Coin envelopes for cashiers. 2. Return envelopes. 3. Light bulbs for night depository. 4. Cashier daters and other forms and supplies. All Other: 1. Bank night depository fee. 2. Postage due on bill payments. 3. Amount of cashiers' and collectors' overages and shortages. 4. Counterfeit money replacement. 5. Night depository bag rental. 6. Return to finder, money found on premises and turned over to cashier.
774	9030005	Collection Agents Fees & Exp	This account shall include commissions, fees, and expenses of agents, such as drug stores, banks, food stores, etc., engaged in the collection of active electric accounts. Outside Service: Collection agents' fees and expenses. Material: Collection agents' receipting stamps
775	9030006	Credit & Oth Collection Activi	This account shall include the cost of labor, materials used, and expenses incurred in investigating customers' credit rating, handling customers' deposits, preparing lists, letters, etc., relating to delinquent accounts for collection, maintaining files of delinquent accounts and making reports in connection therewith. Expenses incurred in connection with merchandise activities should not be charged to this account. Payroll Labor: 1. Approving applications for credit. 2. Balancing customers' deposit records. 3. Checking new applications for service against accounts charged off and final bill file. 4. Checking delinquent notices for prior payment. 5. Disconnecting and reconnecting meters or service due to nonpayment of account when done by others for collectors. Note: A. When this work is performed by collectors, the cost shall be considered incidental to collecting and Account 9030007, Collectors, shall be charged. B. Amounts billed to customers for disconnecting and reconnecting meters, or services, due to nonpayment of account, shall be credited to Account 451000, Miscellaneous Service Revenues. 6. Issuing, refunding and applying customers' deposits. 7. Maintaining: A. Customers' deposit index file. B. Final bill collection follow-up file. C. File of uncollectible accounts. D. File of collection letters. E. File of unpostable deposits. 8. Posting payments of past due accounts to billing/open balance register. 9. Posting disconnects for nonpayment to records. 10. Preparing collection lists and payment reports for use by company collectors and outside collection agencies. 11. Preparing and mailing collection notices and letters on inactive accounts. 12. Recording bad checks received from customers. Outside services: 1. Commissions and fees paid for collecting delinquent electric final billed accounts. 2. Payments to credit organizations for investigations and reports. Material: 1. Forms used in connection with collecting delinquent accounts, except delinquent notices and past due notices for final billed accounts. 2. Socket disconnect sleeves when used for nonpayment disconnects. All other: 1. Dues in credit organizations. 2.
776	9030007	Collectors	This account shall include the cost of labor and expenses of employees engaged in the collection of delinquent accounts and others of a special nature as described herein. Payroll Labor: 1. Collecting by collectors of accounts for which bad checks had been received from customers. 2. Collecting delinquent accounts. 3. Disconnecting and reconnecting meters or services due to nonpayment of account when such work is performed by collectors and is incidental to collecting. (In other cases refer to Account 9030006, Credit
777	9030009	Data Processing	This account shall include all costs associated with the data processing for customer accounting including machine rentals, machine operations, dataentry, forms and supplies and clerical. Payroll Labor: Cash processing. Delinquent accounts. Billing File Maintenance. Meter reading documents Materials: Cards, forms, delinquent notices for active and inactive accounts, window mailing envelopes, stationery and other supplies applicable hereto. Outside Services: Rental expense of data processing equipment. Rental of inserting equipment. Rental of terminal
778	9040007	Uncoll Accts - Misc Receivable	This account is used to track Uncoll Accts - Misc Receivable

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
			This account shall include the cost of labor, materials used, and expenses incurred in connection with customer accounts expenses not provided for or not readily assignable to other accounts. Payroll Labor: 1. Cremating or otherwise disposing of customers' billing and accounting records. 2. General clerical, stenographic and miscellaneous labor not provided for in the foregoing accounts. 3. Information clerk for local accounting office only. 4. Packaging customer accounting records for interoffice shipment. 5. Telephone operator for local accounting office only. 6. Driving car or truck for interoffice messenger service, making deliveries and pickup of meter reading documents, billing registers, cashiers' coupons, etc., between local accounting and collection offices and centralized customer accounting. Outside Services: Interoffice transportation service, other than by company fleet, making deliveries and pickups of meter reading documents, billing registers, cashiers' coupons, etc., between Accounting Offices and centralized customer accounting. Window cleaning, guard service, etc. (if no clearing account). Material: 1. First aid kits and medical supplies. 2. Office supplies for general use in Accounting Offices. All Other: 1. All leased communications equipment associated with customer accounts expenses, including leased circuits, voice communication, microwave dial terminating equipment, etc. 2. Other telephone and telegraph expenses. 3. Post office box rental. 4. Postage not provided for in other accounts. 5. Rents associated with buildings used exclusively for customer accounts functions, including communications with customers.
779	9050000	Misc Customer Accounts Exp	This account includes the cost of individual business and professional memberships; see Account 4265004 for social memberships and related expenses and see Account 9302000 for corporate memberships such as for industry dues, e.g., EEI.
780	9070000	Supervision - Customer Service	This account shall include the cost of labor and expenses incurred in the general direction and supervision of customer service activities, the objective of which is to encourage safe, efficient and economical use of the utility's service. Include herein only that portion of salaries and expenses of Region and Office supervisory and related secretarial personnel which relates to general supervision of customer service and informational expenses activities work provided for in accounts - 9080000 - Customer Assistance Expenses 9090000 - Informational and Instructional Advertising Expenses 9100000 - Miscellaneous Customer Services and Informational Expenses Direct supervision of a specific activity within customer service and informational expenses classification shall be excluded from this account and charged to the account(s) wherein the cost of such activity are included.
781	9070001	Supervision - DSM	This accounts shall include the cost of labor and expenses incurred in the general direction and supervision of Demand Side Management activities, the objective of which is to encourage safe, efficient and economical use of electric energy.
782	9070014	DSM Costs Deferred - TEXAS	To record Deferred DSM Over/Under Collections - Texas Jurisdictions ONLY
783	9080000	Customer Assistance Expenses	This account shall include the cost of labor, materials used and expenses incurred in providing instructions or assistance to customers, the object of which is to encourage safe, efficient and economical use of the utility's service. Payroll Labor: Direct supervision of customer assistance activities. Processing customer inquiries relating to - Proper use of electric equipment, the replacement of such equipment, and requests for information related to such equipment. Nutrition, preparation and preservation of food, textile care and farm practices. Instruction on heat loss computation, insulation, lighting and design standards. Traffic counts, employment data and population trends. Providing advice to customers and working with contractors and manufacturers in the selection and installation of electric equipment in order to achieve the most efficient and safest use of such equipment. Preparing layouts of customers' planned electrical facilities and coordinating with other departments on customer owned facilities. Demonstrations, exhibits, lectures and other programs designed to instruct customers in the safe, economical or efficient use of electric service, and/or oriented toward conservation of energy. Engineering and technical advice to customers, the object of which is to promote safe, efficient and economical use of the utility's service. Making recommendations for power factor correction, controlling demand and conserving energy through more efficient operation. Discussions with customer regarding the capacity of customer's equipment to serve his needs. Discussing and implementing the Volunteer Emergency Power Plan as it pertains to possible curtailment of use of customers' equipment. All Other: Loss in value on equipment and appliances used for customer assistance programs. Note A: Exclude from this account and charge to Account 9080013, Customer Assistance Expenses - RIF Program, the cost of customer assistance expenses applicable to the Residential Insulation Financing Program.
784	9080001	DSM-Customer Advisory Grp	This account shall include the cost of labor, materials used and expenses incurred in providing instructions or assistance to customers in the Demand Side Management customer advisory group.

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
785	9080004	Cust Assistnce Exp - DSM - Ind	This account shall include the cost of labor, materials used, and expenses incurred in providing instructions or assistance to customers in connection with various Demand Side Management programs, the object of which is to encourage safe, efficient, and economical use of the utility's service and to educate customers about energy conservation. The costs of various demand side management programs should be specifically identified by special codes as subaccounts of this account. Note: This account is reserved for use by Indiana Michigan Power Company only.
786	9080009	Cust Assistance Expense - DSM	This account shall include Demand Side Management program expenses including previously deferred expenses being recovered over a limited recovery period.
787	9080014	DSM Costs Deferred	To record deferred DSM (Demand Side Management) costs.
788	9090000	Information & Instruct Advrtis	This account shall include the cost of labor, materials used, and expenses incurred in activities which primarily convey information as to what the utility urges of suggests customers should do in utilizing electric service to protect health and safety, to encourage environmental protection, to utilize their electric equipment safely and economically, or to conserve electric energy. Payroll Labor: 1. Direct supervision of informational activities. 2. Preparing informational materials for newspapers, periodical, billboards. etc., and preparing and conducting informational motion pictures, radio and television programs. 3. Preparing informational booklets, bulletins, etc., used in direct mailings. 4. Preparing informational window and other displays. 5. Employing agencies, selecting media and conducting negotiations in connection with the placement and subject matter of information programs. Outside Services: 1. Newspaper, periodical, billboard, radio, television space and production expense. 2. Agency fees. Material: 1. Informational booklets, dodgers, bulletins, etc. 2. Supplies for preparation of informational
789	9100000	Misc Cust Svc&Informational Ex	This account shall include the cost of labor, materials used, and expenses incurred in connection with the customer service and informational activities which are not includible in other customer service and informational expense accounts. Payroll Labor: 1. Industry, Trade and Civic Group meetings and activities, such as - A. Attendance and participation in group meetings or organizations such as Edison Electric Institute, Chamber of Commerce, Builders and Homebuilders Associations, AEP Annual Management Meeting, Tax Associations, Service Clubs, Civic Groups and Charitable organizations. B. Work in connection with group activities, such as fund drives, community projects and workshops. C. Company representation at meetings of Zoning Boards, Planning Commissions and with other Utilities on Matters of customer service interest. D. Contact with governmental agencies on matters affecting customer service activities, other than political or regulatory activities. 2. General clerical and stenographic work not assigned to specific customer service and informational programs. 3. Other labor of a miscellaneous nature. Material: 1. Forms, stationery and office supplies. All Other: 1. Postage for general use. 2. Communication service. Note A: Exclude from this account and charge to Account 9100003, Miscellaneous Customer Service and Informational Expenses - RIF Program, those miscellaneous costs that are applicable to the Residential Insulation Financing Program. This account includes the cost of individual business and professional memberships; see Account 4265004 for social memberships and related expenses and see Account 9302000 for corporate memberships such as for industry dues, e.g., EEI.
790	9100001	Misc Cust Svc & Info Exp - RCS	This account shall include the cost of labor, materials used, and expenses incurred in connection with customer service and informational activities related to the Residential Conservation Service Program. Payroll Labor: General, administrative, clerical, stenographic, and other labor. All Other: 1. Any liability for damages which arise from the audit which is the responsibility of the utility company.
791	9110001	Supervision - Residential	This account shall include the cost of labor and expenses incurred in the general direction and supervision of residential sales activities.
792	9110002	Supervision - Comm & Ind	This account shall include the cost of labor and expenses incurred in the general direction and supervision of commercial and industrial sales activities.

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Line No.	G/L Account	Account Description	Additional Description
793	9120000	Demonstrating & Selling Exp	This account shall include the cost of labor, material used, and expenses incurred in promotional demonstrating, and selling activities, except by merchandising, the object of which is to promote or retain the use of utility services by present or prospective customers. Payroll Labor: 1. Demonstrating uses of utility services. 2. Conducting cooking schools, preparing recipes, and related home service activities. 3. Exhibitions, displays, lectures, and other programs designed to promote use of utility services. 4. Experimental and development work in connection with new and improved appliances and equipment, prior to general public acceptance. 5. Solicitation of new customers or of additional business from old customers, including commissions paid employees. 6. Engineering and technical advice to present or prospective customers in connection with promoting or retaining the use of utility services. 7. Special customer canvasses when their primary purpose is the retention of business or the promotion of new business.
794	9120001	Demo & Selling Exp - Res	This account shall include the cost of labor, material used, and expenses incurred in promotional demonstrating, and selling activities, except by merchandising, the object of which is to promote or retain the use of utility services by present or prospective residential customers. Payroll Labor: 1. Demonstrating uses of utility services. 2. Conducting cooking schools, preparing recipes, and related home service activities. 3. Exhibitions, displays, lectures, and other programs designed to promote use of utility services. 4. Experimental and development work in connection with new and improved appliances and equipment, prior to general public acceptance. 5. Solicitation of new customers or of additional business from old customers, including commissions paid employees. 6. Engineering and technical advice to present or prospective customers in connection with promoting or retaining the use of utility services. 7. Special customer canvasses when their primary purpose is the retention of business or the promotion of new business.
795	9130001	Advertising Exp - Residential	This account shall include the cost of labor, materials used, and expenses incurred in advertising designed to promote or retain the use of utility service applicable to residential customers, except advertising the sale of merchandise. Payroll Labor: 1. Preparing advertising material for newspapers, periodicals, billboards, etc., and preparing and conducting motion pictures, radio and television programs. 2. Preparing booklets, bulletins, etc., used in direct mail advertising. 3. Preparing window and other displays. 4. Clerical and stenographic work. 5. Investigating advertising agencies and media and conducting negotiations in connection with the placement and subject matter of sales advertising. Note: A. Exclude from this account all institutional or goodwill advertising which is provided for under sub accounts of Accounts 9301000, General Advertising Expenses. B. Exclude from this account the cost of publication of stockholder reports, dividend notices, bond redemption notices, financial statements, and other notices of a general corporate character which are provided for under sub accounts of Account 9302000, Miscellaneous General Expenses. THIS ACCOUNT SHOULD BE USED FOR LABOR CHARGES ONLY.
796	9200000	Administrative & Gen Salaries	This account shall include the salaries of employees in all departments except those relating to nuclear, power generation, energy transmission and energy distribution. Payroll Labor: Human Resources: Administration of labor relations, including: Handling labor negotiations. Handling grievance and arbitration procedures. Preparing and maintaining seniority lists. Making contract surveys. Wage and salary administration, including: Maintaining employee personnel records. Preparing employee personnel reports. Processing changes of status and employment record cards. Making wage and salary surveys. Preparing job specifications of descriptions. Preparing organization charts. Selecting, investigating, interviewing and hiring company personnel. 2. Customer Services: Conduct economic studies of areas subject to unusual growth. Prepare reports of anticipated load growth and conduct plant relocation studies in connection with customer expansion, relocation or movement into service area. Provide housing completion data, standard industrial classifications, tariff and rate applications for management guidance in load growth projection and company facility development. Conduct studies of possible site locations for company facilities. Contact customers and advise management regarding mass vacation schedules. Analyze economics of providing service to new loads. Note: The portion of the salaries of certain personnel in this group which has been determined as chargeable to construction shall be credited to Account 9220001, Administrative Expense Transferred to Construction.

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
797	9200005	GridSmart Reimbursement Contra	THIS ACCOUNT SHOULD BE USED FOR CONTRA 9200000 GRIDSMART LABOR REIMBURSEMENTS ONLY. This accounts shall include the Federal Stimulus Reimbursement Dollars for Ohio Gridsmart related to 9200000 labor. The Cost Components charged to this account should be limited to 974 and 979 for appropriate GridSmart over/under tracking purposes. This account should not be subject to combo edit rule ACCTC_LBR.
798	9210001	Off Supl & Exp - Nonassociated	This account shall include the cost of office supplies and expenses incurred by employees related to nonassociated companies of all departments except those relating to nuclear, power generation, energy transmission and energy distribution. Material: Forms, books, binders, stationery, office supplies. All Other: 1. Cafeteria expenses. Communication service. Postage Rental on postage meter machines for general mail. Applicable portion of billings by the Service Corporation. Note: 1. The portion of expenses included herein which have been determined as chargeable to construction shall be credited to Account 9220001, Administrative Expenses Transferred to Construction, and to Account 9220002, Administrative Expenses Transferred to Construction - Managerial, as indicated in these two accounts. This account includes the cost of individual business and professional memberships; see Account 4265004 for social memberships and related expenses and see Account 9302000 for corporate memberships such as for industry dues, e.g., EEI.
799	9210002	Off Supl & Exp - Associated	This account shall include the cost of office supplies and expenses incurred by employees related to associated companies of all departments except those relating to nuclear, power generation, energy transmission and energy distribution. Material: Forms, books, binders, stationery, office supplies. All Other: 1 Cafeteria expenses. Communication service. Postage Rental on postage meter machines for general mail. Applicable portion of billings by the Service Corporation. Note: 1. The portion of expenses included herein which have been determined as chargeable to construction shall be credited to Account 9220001, Administrative Expenses Transferred to Construction, and to Account 9220002, Administrative Expenses Transferred to Construction - Managerial, as indicated in these two accounts.
800	9210003	Office Supplies & Exp - Trnsf	This account shall be credited with the applicable portion of expenses of employees of Accounting Services and the Human Resources Department referred to in Account 9200003, Administrative and General Salaries Transferred including office supplies and expenses which are determined as properly chargeable to Retirement or includible in billings to Associated Companies or Others. The credits hereto shall be the applicable portion of charges initially recorded in - Account 9210000, Office Supplies and Expenses.
801	9210004	Office Utilites	This account is used to track Office Utilites
802	9210005	Cellular Phones and Pagers	This account is used to track Cellular Phones and Pagers
803	9210006	O&M Reconciliation	This account will be used to reconcile the elimination of intercompany operations and maintenance expense accounts. This account should only be charged on elimination business units and only used by Financial Reporting. The
804	9210007	Dresden Off Supl & Exp Nonasoc	APCo's Virginia Generation Rate Adjustment Clause (G-RAC original case number PUE-2011-00036) related to office supply and expense associated with the Dresden Generating Plant over/under accounting. Subsequent case numbers will not be included in this description.
805	9220000	Administrative Exp Trnsf - Cr	This account shall be credited with the applicable portion of salaries and expenses of all Administrative Departments which are determined as properly chargeable to Construction.
806	9220001	Admin Exp Trnsf to Cnstrction	This account shall be credited with the applicable portion of salaries and expenses of Accounting Services and the Human Resources Department which are determined as properly chargeable to Construction. Representative Personnel: Accounts Payable Section Owned Asset Accounting Section; Payroll Section Human Resources Director, Supervisors and Assistants Secretarial personnel responsible to above groups. All Other: Credits hereto shall be the applicable portion of charges initially recorded in - Account 9200000, Administrative & General Salaries.
807	9220004	Admin Exp Trnsf to ABD	This account shall be credited with the applicable portion of salaries and expenses of all Administrative Departments which are determined as properly chargeable to Associated Business Development.
808	9230001	Outside Svcs Empl - Nonassoc	This account shall include the fees and expenses of professional consultants, accountants and auditors, attorneys and others for general services.

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Line No.	G/L Account	Account Description	Additional Description
809	9230003	AEPSC Billed to Client Co	This account shall include the fees and expenses of AEPSC billed to associated companies.
810	9240000	Property Insurance	This account shall include property insurance administration costs other than premiums in connection with losses and damages to owned or leased property used in utility operations. It shall also include special costs incurred in procuring insurance, such as insurance inspection service, and the pay, traveling, and office expenses of officers, clerks, and other employees of the Insurance Department. All Other: 1. Charge here the billing by the Service Corporation for salaries and expenses incurred in the administration of the property insurance program.
811	9250000	Injuries and Damages	This account shall include the cost of insurance or reserve accruals to protect the utility against injuries and damages claims of employees or others, losses of such character not covered by insurance, and expenses incurred in settlement of injuries and damages claims. Reimbursements from insurance companies or others for expenses charged hereto on account of injuries and damages and insurance dividends or refunds shall be credited to this account.
812	9250001	Safety Dinners and Awards	This account shall include all costs incurred for dinners and awards given to employees, including those at generating stations, in connection with the administration of the safety program in recognition of favorable or outstanding achievement in accident prevention. Payroll Labor: Preparing and serving meals in the company kitchens. Material: 1. Individual or group awards 2. Food All Other: Cost of dinner at club, restaurant or catering service for dinner if held on company premises
813	9250002	Emp Accdent Prvntion-Adm Exp	This account shall include the applicable portion of the cost of labor, materials used, and expenses incurred by the Human Resources and Safety Directors, Safety Supervisors, assistants and related clerical and stenographic employees, including those at generating stations, regularly engaged in accident prevention, safety and health administration work. Payroll Labor: 1. Attendance at company or outside meetings by Safety Supervisor and preparing others to conduct safety training meetings and demonstrations. 2. Investigating accidents and general health conditions of company employees. 3. Inspecting hazardous conditions. (Adjustment of such conditions shall be charged to the appropriate operating or plant account.) 4. Preparing accident reports and maintaining records. Outside Services: Expense of intra company movement of films and training equipment. The time of employees who attend safety meetings, shall be charged to the account appropriate to the duties performed, either immediately preceding of following the meeting, or to the account to which their time is
814	9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	This account is to cover expenses associated with both occupational and non-occupational charges to administer the self insured and insured, sick pay and workers compensation programs. Includes: Portions of the amortization of premiums for worker's compensation and accruals under the self-insurance program. Amortization of the premium for excess or catastrophic insurance in connection with worker's compensation insurance. Assessments and Renewal Fees paid to a State's Compensation Commission. Outside Services such as legal fees, vendor costs, consulting charges and expenses specifically identifiable with worker's compensation and sick pay administration Notes: Premiums paid by the utility on outside contractor's labor, when the contractor does not have the required coverage, should be charged to the account appropriate for the work performed. Credit hereto the amount of worker's compensation insurance transferred to Construction, Retirement, or included in billings to associated companies or to others. Amounts relating to transportation and garage equipment shall be charged to Transportation Expense Clearing. Amounts relating to materials and supplies shall be charged to Account 163 Stores Expenses Undistributed

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Line No.	G/L Account	Account Description	Additional Description
815	9250007	Prsnal Injries&Prop Dmage-Pub	This account shall include all costs incurred in connection with public liability claims, including injuries to persons other than employees and damages to property of others not covered by insurance. Payroll Labor: 1. Investigating accidents where Company is not involved as a precaution against unjust claims. 2. Portion of time employee on fixed classification doing routine field or office work which may be applicable to accounting for injuries and damages either to persons or property. 3. Time of employee on diversified classification: A. Attending court as witness in damage suit. B. Attending funeral of non-employee killed in accident involving the Company. C. Investigating injury to non-employee or damage to property of others. D. Taking pictures at location of injury to non-employee or damage to property of others. Outside Services: Legal fees and expenses. All other: 1. Amounts paid in settlement of claims of persons other than employees for personal injuries. 2. Amounts paid in settlement of claims for damage to property of others (includes cost of repairs). 3. Damage not planned and unforeseen. Note: Cost of damages to property of others made necessary by construction, maintenance, or retirement should be charged to the work order or other appropriate account according to the work performed.
816	9250010	Frg Ben Loading - Workers Comp	This account is used for tracking fringe benefit loading for Workers Comp.
817	9260000	Employee Pensions & Benefits	This account shall include pensions paid to or on behalf of retired employees, or accruals to provide for pensions, or payments for the purchase of annuities for this purpose, when the utility has definitely, by contract, committed itself to a pension plan under which the pension funds are irrevocably devoted to pension purposes, and payments for employee accident, sickness, hospital, and death benefits, or insurance therefor. Include also, expenses incurred in medical, educational or recreational activities for the benefit of employees, and administrative expenses in connection with employee pensions and benefits.
818	9260001	Edit & Print Empl Pub-Salaries	This account shall include payroll labor costs, employee expenses and automotive expenses incurred in connection with editing employees' newspapers or magazines. Payroll Labor: Note: 1. Charge account 9260015, Editing and Printing Employee Publications - Expenses, for printing costs incurred in connection with publication of employees' newspapers or magazines.
819	9260002	Pension & Group Ins Admin	This account shall include the salaries and other expenses of the Human Resources Director, Human Resources Supervisor, Safety Supervisor, assistants and related clerical and stenographic employees, including those at generating stations, regularly engaged in the administration of the pension, group life and medical insurance plans. Payroll Labor: 1. Administering employee sick pay plan. 2. Handling claims for employees under group life and medical insurance plans. 3. Maintaining records relating to the pension, group life and medical plans and preparing reports. Outside Services: 1. Consulting actuary or insurance consultant. 2. Charge by Trustee for Administration of Pension Fund. Material: Informatory literature for employees pertaining to all of these plans.
820	9260003	Pension Plan	This account shall be charged with contributions to the Retirement Trust Fund. All Other: 1. Payments made by the company. 2. Charge by the Service Corporation for the Appropriate portion of its contribution. 3. Credit memoranda received under Group Annuity Contracts covering withdrawals and dividends. Note: Refer to - Account 9260031, Pension Costs Transferred to Construction. Account 9260032, Pension Cost Transferred to Retirement. Account 9260033, Pension Costs Transferred to Other Accounts for pension costs related to labor chargeable to construction, retirement or other accounts.
821	9260004	Group Life Insurance Premiums	This account shall include the company's portion of the cost of premiums for Group Life Insurance for company employees. The applicable portion of charges to this account determined to be properly chargeable to Construction shall be credited to Account 9260034, Group Insurance Costs Transferred to Construction. The portion properly chargeable to Retirement, includible in billings to Associated Companies or Others, or transferred to accounts other than Construction shall be credited to Account 9260035, Group Insurance Costs Transferred to
822	9260005	Group Medical Ins Premiums	This account shall include the company's portion of the cost of premiums for Group Medical (Hospitalization) Insurance for company employees. The applicable portion of charges to this account determined to be properly chargeable to Construction shall be credited to Account 9260034, Group Insurance Costs Transferred to Construction. The portion properly chargeable to retirement, includible in billings to Associated Companies or Other, or transferred to accounts other than Construction shall be credited to Account 9260035, Group Insurance Costs
823	9260006	Physical Examinations	This account shall include the cost of periodic and preemployment examinations for employees, including those at generating stations. Outside Services: Doctors' services
824	9260007	Group L-T Disability Ins Prem	This account shall include the company's portion of the cost of premiums for Groups Long-term Disability Insurance for company employees. The applicable portion of charges to this account determined to be properly chargeable to Construction shall be credited to Account 9260034, Group Insurance Costs Transferred to Construction. The portion properly chargeable to Retirement, includible in billings to Associated Companies or Other, or transferred to accounts other than Construction shall be credited to Account 9260035, Group Insurance costs Transferred to

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
825	9260009	Group Dental Insurance Prem	This account shall include the company's portion of the cost of premiums for Group Dental Insurance for company employees. The applicable portion of charges to this account determined to be properly chargeable to Construction shall be credited to Account 9260034, Group Insurance Costs Transferred to Construction. The portion properly chargeable to Retirement, includible in billings to Associated Companies or Others, or transferred to account other than Construction shall be credited to Account 9260035, Group Insurance Costs Transferred to Other
826	9260010	Training Administration Exp	This account shall include the cost of materials used and expenses incurred in connection with the administration of training programs for employees at all levels. Includes also training programs for employees at generating stations. Payments to employees under the educational assistance program shall be charged to Account 9260014, Educational Assistance Payments. Include in this account charges by other departments for employees engaged in the performance of duties applicable to this activity such as transporting personnel of supplies to airports, stations or other locations as require and the preparation of charts, graphs, etc. Material: Booklets, newsletters, posters, students' and instructors' course materials. Employee Expenses: Expenses of employees engaged in administering and conducting employee training program. Note:
827	9260012	Employee Activities	This account shall include the cost of labor, materials used, and expenses incurred in connection with employee social and athletic activities such as picnics, parties, dances, softball, baseball, tennis ,bowling, etc. Includes also service pin dinners and other veterans' activities. Also include herein the cost of activities for employees at generating stations. Payroll Labor: Preparing and serving meals and other labor related to the activities referred to above. Material: Food, refreshments, prizes, athletic equipment, decorations, etc. All Other: Payments by company to employee social and athletic funds. Catering service
828	9260014	Educational Assistance Pmts	This account shall include payments to employees (reimbursement) or to schools in connection with the educational assistance program. Include herein educational assistance payments to employees at generating stations.
829	9260021	Postretirement Benefits - OPEB	This account shall be charged with the cost of other postretirement benefits computed pursuant to Statement of Financial Accounting Standards No. 106.
830	9260026	Savings Plan Administration	This account shall include the applicable portion of the salaries and expenses of employees, including those at generating stations, regularly engaged in the administration of AEP System Employees Savings Plan. Outside Services: 1. Charge by Trustee for administration of the Savings Plan Fund. Material: 1. Informational literature for employees. 2. Forms and supplies.
831	9260027	Savings Plan Contributions	This account shall be charged with employer contributions to the AEP System Employees Savings and Thrift Plans. All Other: 1. Payments made by the employer on behalf of its employees. 2. Credits for employee forfeitures of employer monies.
832	9260036	Deferred Compensation	This account shall include all costs associated with deferred compensation to employees.
833	9260037	Supplemental Pension	This account shall include costs associated with supplemental pension plans.
834	9260040	SFAS 112 Postemployment Benef	This account shall include all costs involving other post retirement benefits.
835	9260042	SERP Pension - Non-Service	To record the Non-Service components of the SERP Pension plan cost.
836	9260043	OPEB - Non-Service	To record the Non-Service components of the OPEB plan cost.
837	9260050	Frg Ben Loading - Pension	This account is used to track Frg Ben Loading - Pension
838	9260051	Frg Ben Loading - Grp Ins	This account is used to track Frg Ben Loading - Grp Ins
839	9260052	Frg Ben Loading - Savings	This account is used to track Frg Ben Loading - Savings
840	9260053	Frg Ben Loading - OPEB	This account is used to track Frg Ben Loading - OPEB
841	9260055	IntercoFringeOffset- Don't Use	This account is used to track IntercoFringeOffset- Don't Use
842	9260057	Postret Ben Medicare Subsidy	This account shall be charged with the Medicare Part D subsidy of other postretirement benefits. UMWA medicare subsidies should be recorded in account 4265025.
843	9260058	Frg Ben Loading - Accrual	This account allows for a State/Jurisdiciton or a blank value due to some business units requiring state This account is used to track the fringe benefit loading for accrued payroll.
844	9260060	Amort-Post Retirerment Benefit	This account will be used to amortize the related regulatory assets in account 1823299 over twelve years, the approximate term of the related postretirement benefit (commonly referred to as OPEB) cost period used to amortize the actuarial gain (the OPEB period) effective January 2013.
845	9260062	Pension Plan - Non-Service	To record the Non-Service components of the Qualified Pension plan cost.

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
846	9270000	Franchise Requirements	This account shall include charges of the following nature: 1. Periodic payments to municipal or other governmental authorities without reimbursement in compliance with franchise, ordinance or similar requirements. Note: A. Taxes shall not be charged to this account, but to Account 4082000, Taxes Other Than Income Taxes. B. Initial consideration (one agreed amount) for franchise running for more than one year shall be charged to Account 302, Franchises and Consents. 2. Electric Service, computed at regular tariff rates, furnished to municipal or other governmental authorities without charge under provision of franchises Note: When no direct outlay is involved, concurrent credit for such charges shall be made to Account 9290000, Duplicate Charges - Credit 3. Cost of materials, supplies and services furnished municipal or other governmental authorities without reimbursement in compliance with franchise. Note: The cost of plant, materials, supplies, etc., given as an initial consideration for a franchise running for more than one year shall be charged to Account 302, Franchises and Consents. 4. Cost of bond furnished municipality for faithful performance of contract for utility service in accordance with requirement of franchise. 5. Premium on Street Lighting Bond to guarantee faithful performance of contract.
847	9280000	Regulatory Commission Exp	This account shall include payments made to a state regulatory commission for assessments identified with specific services performed.
848	9280001	Regulatory Commission Exp-Adm	This account shall include payments made to a state regulatory commission for assessments identified with specific services performed other than in connection with formal cases. Also include payments made to the United States for the administration of the Federal Power Act. Amounts of regulatory commission expenses which by approval or direction of the Commission are to be spread over future periods shall be charged to Account 1860000, Miscellaneous Deferred Debits, and amortized by charges to this account. All Other: Payments to Federal or State Regulatory Commissions for Administrative expenses of the Commissions. Federal Administration Fee for - A. Claytor Hydro Project (AP Co.) B. London Hydro Project (AP Co.) C. Marmet Hydro Project (AP Co.) D. Winfield Hydro Project (AP Co.) E. Smith Mountain Hydro Project (AP Co.) Note: Exclude from this account and include in Account 4080000, Taxes Other Than Income Taxes, any "remainder assessments" paid to state utility commissions.
849	9280002	Regulatory Commission Exp-Case	A. This account shall include all expenses (except pay of regular employees only incidentally engaged in such work), properly includible in electric operating expenses, incurred by the utility in connection with formal cases before regulatory commissions, or other regulatory bodies, or cases in which such a body is a party, including payments made to a regulatory commission for fees assessed against the utility for the pay and expenses of such commission, its officers, agents and employees. B. Amounts of regulatory commission expenses which by approval or direction of the Commission are to be spread over the future periods shall be charged to Account 1860000, Miscellaneous Deferred Debits, and amortized by charges to this account. C. The utility shall be prepared to report the cost of each formal case. Items: 1. Salaries, fees, retainers, and expenses of counsel, solicitors, attorneys, accountants, engineers, clerks, attendants, witnesses, and others engaged in the prosecution of, or defense against, petitions of complaints presented to regulatory bodies, or in the valuation of property owned or used by the utility in connection with formal cases. 2. Expenses: Engineering supplies, office expenses, payments to public service or other regulatory commissions, stationery and printing, traveling expenses, and other expenses incurred directly in connection with formal cases before regulatory commissions. Note: A. Exclude from this account and include in other appropriate operating expense accounts, expenses incurred in the improvement of service, additional inspection, or rendering reports, which are made necessary by the rules and regulations, or orders, of regulatory bodies. B. Do not include in this account amounts includible in Account 302,

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
850	9280005	Reg Com Exp-FERC Trans Cases	A. This account shall include all expenses (except pay of regular employees only incidentally engaged in such work), properly includible in electric operating expenses, incurred by the utility in connection with formal cases before the FERC, or other federal regulatory bodies relating to the transmission formula rates, or cases in which such a body is a party, including payments made to a regulatory commission for fees assessed against the utility for the pay and expenses of such commission, its officers, agents and employees. B. Amounts of regulatory commission expenses which by approval or direction of the Commission are to be spread over the future periods shall be charged to Account 1860000, Miscellaneous Deferred Debits, and amortized by charges to this account. C. The utility shall be prepared to report the cost of each formal case. Items: 1. Salaries, fees, retainers, and expenses of counsel, solicitors, attorneys, accountants, engineers, clerks, attendants, witnesses, and others engaged in the prosecution of, or defense against, petitions of complaints presented to regulatory bodies, or in the valuation of property owned or used by the utility in connection with formal cases. 2. Expenses: Engineering supplies, office expenses, payments to public service or other regulatory commissions, stationery and printing, traveling expenses, and other expenses incurred directly in connection with formal cases before regulatory commissions. Note: A. Exclude from this account and include in other appropriate operating expense accounts, expenses incurred in the improvement of service, additional inspection, or rendering reports, which are made necessary by the rules and regulations, or orders, of regulatory bodies. B. Do not include in this account amounts
851	9301000	General Advertising Expenses	This account shall include the cost of labor, materials used, and expenses incurred in advertising and related activities which by their content and purpose are not provided for elsewhere.
852	9301001	Newspaper Advertising Space	This account shall include the cost of space in newspapers for institutional and goodwill advertising, the object of which is to promote and improve public relations. All Other: Cost of space in newspapers.
853	9301002	Radio Station Advertising Time	This account shall include the cost of radio station time for the broadcast of announcements and presentation of programs, the object of which is to promote and improve public relations. All Other: Cost of radio time.
854	9301003	TV Station Advertising Time	This account shall include the cost of television station time for announcements and presentation of programs the object of which is to promote and improve public relations All Other: Cost of television time.
855	9301010	Publicity	This account shall include the cost of publicity services, material, expenses and labor incurred in preparing and releasing to news media and trace press various news releases and photographs. Payroll Labor: Outside Services: Agency fees for engraving, preparing mats, clipping service and photographic work. Material: Mats, plates and company photographic supplies.
856	9301012	Public Opinion Surveys	This account shall include the cost of labor, materials used, and expenses incurred in conducting public opinion surveys. Payroll Labor: Employees on diversified classification while engaged in public opinion surveys. Outside Services: Preparation of material and reports. Material: Forms and stationery.
857	9301015	Other Corporate Comm Exp	This account shall include the cost of labor, materials used, and expenses incurred in public affairs activities not elsewhere provided for in the foregoing Accounts 9301011through 9301014 inclusive, the object of which is to promote and improve public relations such as: A. Contributions for conventions or meetings of the industry. B. Reddy Kilowatt license fee. C. Special Telephone Listing Expense. Payroll Labor: Charges by Other Departments. Material: Miscellaneous materials for decorations, wire, etc. Note: Include in this account handout items such as, thermometers, pens, knives, lighters, etc.
858	9302000	Misc General Expenses	This account shall include the cost of labor, material used and expenses incurred in connection with general management of the utility not provided for elsewhere. This account includes the cost of corporate memberships such as for industry dues, e.g., EEI; see Account 4265004 for social memberships and see various miscellaneous functional accounts for individual business and professional memberships.
859	9302003	Corporate & Fiscal Expenses	This account shall include the cost of labor, material used and expenses incurred in connection with Corporate and Fiscal expenses of the utility. Payroll Labor: Material: Binders, forms and stationery for financial notices and reports to Regulatory Commissions, Stockholders, etc. All Other: Dividend and other financial notices. Public notices of financial, operating, and other data required by regulatory statutes, not including, however, notices required in connection with security issues or acquisitions of property. Publishing and distributing annual reports to stockholders and financial institutions. Stockholders' meeting expenses. Trustee, registrar and transfer agent fees and expenses. (Exclude trustee fee for administration of Retirement Trust Fund. Refer to Account 9260002, Pension and Group Insurance Administration). Directors' fees and expenses.

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
860	9302004	Research, Develop&Demonstr Exp	This account shall include the cost of research, development and demonstration expenses not charged to other operation and maintenance expense accounts on a functional basis, as cleared from Account 1880000, Research, Development and Demonstration Expenditures. Note: Costs incurred by the individual operating companies in connection with approved research, development and demonstration projects are billed to the Service Corporation for accumulation with any Service Corporation costs and subsequent rebilling to all operating companies benefited by the project. Billings from the Service Corporation for final recordation in the operating expense accounts will be initially charged to Account 1880000 by the operating company with subsequent clearance to the appropriate functional expense accounts or to Account 9302004 if not chargeable to other functional expense accounts. Billings from the Service Corporation that are chargeable to construction projects will be recorded to the construction
861	9302006	Assoc Bus Dev - Materials Sold	This account shall include the cost of all materials sold to non-affiliated companies where the AEP company is not acting as a contractor nor is it providing the labor to install the materials sold.
862	9302007	Assoc Business Development Exp	This account shall include the cost of all non-energy transmission and distribution business expenses related to Associated Business Development where the AEP company is acting as the contractor (i.e., AEP company is providing the material and the labor to install the material).
863	9302458	AEPSC Non Affliated expenses	To accumualte all AEPSC charges for non affiliated work in one account.
864	9310000	Rents	This account shall include rents, or the appropriate portion thereof, properly includible in electric utility operations of equipment or property used in connection with general administration functions and not directly chargeable to other accounts. Exclude building rentals and rentals charged to clearing accounts. All Other: Rental of parking areas for general company use. Rental charges paid to sign companies for signs on local offices, substations, etc., for company and/or facility identification.
865	9310001	Rents - Real Property	This account shall include rents properly includible in electric operating expenses covering buildings or offices used or occupied in connection with the customer service and informational, sales, and administrative and general functions. Include improvements made to property leased for a period of more than one year if the cost of each improvement is relatively minor or if the lease is for a period of not more than one year. Charge the improvement costs to this account either directly or by amortization. All Other: Notes: A. Rents paid for use of buildings or lots for storage of materials and supplies shall be charged to Account 1630000, Stores Expense Undistributed. B. Rents paid for the use of buildings or lots for garage purposes or storage space for company automotive fleet shall be charged to Transportation Expenses - Clearing. C. The cost of substantial initial or subsequent additions, replacements, or betterments should be charged to the electric plant account appropriate for the class of property leased. If the service life of the improvements is terminable by action of the lease, the cost, less net salvage, of the improvements shall be spread over the life of the lease by charges to Account 4040000, Amortization of Limited-Term Electric Plant. If the service life is not terminated by action of the lease but by depreciation proper, the cost of the improvements, less net salvage, shall be accounted for as depreciable plant. D. Rents associated with buildings used exclusively for customer accounts functions, including communications with customers, should be excluded from this account, and charged to Account 9050000,
866	9310002	Rents - Personal Property	This account shall include rents, or the appropriate portion thereof, properly includible in utility operations of equipment or property used in connection with general administration functions and not directly chargeable to other
867	9350000	Maintenance of General Plant	This account shall include the cost of labor, material used, and expenses incurred in the maintenance of general plant equipment assignable to customer accounts, sales, and administrative and general functions, the book cost of which is includible in Account 398.
868	9350001	Maint of Structures - Owned	This account shall include the cost of labor, materials used, and expenses incurred in the maintenance of company-owned structures and improvements, the book cost of which is includible in Account 390, Structures and Improvements. Include herein company-owned Region and District offices, storerooms, garages and other general buildings serving dual purposes. Refer to Electric Plant Instruction 8 in the FPC Uniform System of Accounts for a listing of items includible in the Structure and Improvement account. Also include herein maintenance work such as: 1. Erecting and maintaining signs in parking lots for general company use. 2. Maintaining access roads to company radio and microwave towers and to building housing control equipment. 3. Maintaining buildings housing company radio and microwave equipment. 4. Making and installing markers on land for general use. 5. Renewing refrigerant in air conditioning equipment. 6. Repairing pole storage rack and pole yard fence.

Explanation: Provide a copy of the utility's detailed chart of accounts and subaccounts including plant in the same level of detail required in E-17. Include a detailed description of each account/subaccount.

Line No.	G/L Account	Account Description	Additional Description
869	9350002	Maint of Structures - Leased	This account shall include the cost of labor, materials used, and expenses incurred , when assumed by the lessee, in the maintenance of leased structures and improvements used for general or duel purposes (which if company-owned would be includible in Account 390, Structures and Improvements). Refer to Electric Plant Instruction 8 in the FPC Uniform System of Accounts for a listing of items includible in the Structure and Improvement Account. Also include herein maintenance work such as: 1. Erecting and maintaining signs in parking lots for general company use. 2. Maintaining access roads to company radio and microwave tower and to building housing control equipment. 3. Renewing refrigerant in air conditioning equipment. 4. Repairing pole storage rack and pole yard
870	9350003	Maint of Prprty Held Fture Use	This account shall include the cost of labor, materials used, and expenses incurred with maintaining those properties recorded in Accounts 310, 320, 330, 340, 350, 360, and 389 Land and Land Rights to be used in the future. A representative list of duties to be performed: 1. Chemical killing of weeds 2. Repair fence
871	9350012	Maint of Data Equipment	This account shall include the cost of labor, materials used, and expenses incurred in the maintenance of data network equipment for general use, the book cost of which is includible in Account 397, Communication Equipment. Principal items includible in Account 397 pertaining to data equipment: 1. Data modems. 2. Data multiplexers. 3. Data switches and converters. 4. Terminals, printers, disk drives, and controllers. 5. Terminating/impedance matching devices - combiner splitters, attenuators, bridges, amplifiers, loopback receivers/transmitters, and filters. 6. Relay racks, cabinets. 7. Wire, cable, coax, baluns, connectors, and transmission media. 8. Power supplies, regulators, transformers, AC-DC converters, solar cell, and batteries. Also include herein: 1. Cost of small tools and repairing special testing instruments. 2. Inspecting and testing to locate and clear existing trouble. 3. Inspecting and testing for acceptance of new circuits.
872	9350013	Maint of Cmmncation Eq-Unall	This account shall include the cost of labor, materials used, and expenses incurred in maintenance of communication systems which cannot be accurately allocated to the specific maintenance Accounts 9350021 through 9350026, such as tools, supplies, and office expenses applicable to the entire system.
873	9350014	Maint Supv & Eng-Cmmun Eq	This account shall include the applicable portion of the cost of labor expenses incurred in the general supervision, direction, planning, coordination, instruction, and training in connection with the maintenance of communication equipment classified to Account 397, Communication Equipment. It shall include the portion of services of personnel such as Region and District Supervisors, Engineers, Superintendents, General Foremen, Consultants, and secretarial work for this group. Include herein the general supervision and direction of work as it relates to maintenance only, but not the actual performance of such work or the immediate and direct supervision chargeable to other accounts appropriate for the work performed.
874	9350015	Maint of Office Furniture & Eq	This account shall include the cost of labor, materials used, and expenses incurred in the maintenance of office furniture and equipment assignable to the customer accounts, marketing, and administrative and general functions, the book cost of which is includible in Account 391, Office Furniture and Equipment. Maintenance expenses on office furniture and equipment used elsewhere than in the above-mentioned departments shall be charged as follows: Production - Steam: Account 5140000 Maintenance of Miscellaneous Steam Plant Production - Nuclear:Account 5320000 Maintenance of Miscellaneous Nuclear Plant Production - Hydro:Account 5450000 Maintenance of Miscellaneous Hydraulic Plant Transmission:Account 5730000 Maintenance of Miscellaneous Transmission Plant Distribution:Account 5980000 Maintenance of Miscellaneous Distribution Plant Garages, Shops, Stores, etc.,Appropriate clearing accounts where used
875	9350019	Maint of Gen Plant-SCADA Equ	This account shall include the cost of labor, materials used, and expenses incurred in the maintenance of general plant equipment relating to SCADA equipment.
876	9350024	Maint of DA-AMI Comm Equip	To capture the O&M costs associated with the communications equipment that will be used for Distribution Automation (DA) and Automated Metering Infrastructure (AMI)

For a narrative description of each plant account please see FERC's Code of Federal Regulations, Title 18, Electric Plant Chart of Accounts which provides a description of each plant account. The link is provided below.
https://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&SID=054f2bfd518f9926aac4b73489f11c67&rgn=div5&view=text&node=18:1.0.1.3.34&idno=18

SWEPCO does not maintain a separate plant chart of accounts except for account number and brief line description which less informative than descriptions provided in Title 18 shown in the link above.

Supporting Schedules

Recap Schedules

Southerwestern Electric Power Company **Schedule E-10**
Organizational Charts
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing an organizational chart of the applicant. Said organizational chart shall include the overall corporate structure of the parent corporation and all subsidiary companies, if any. This schedule shall include a detailed chart of the applicant's Accounting Department, Budget department, Finance Department and Rate and Regulatory Department. Provide the name, title, and telephone number of the person who should be contacted for information concerning this application.

Description

SEE ATTACHMENT

All correspondence and questions should be directed to:
Jay E. Toungate
Regulatory Case Manager
214-777-1055

<u>Supporting Schedules</u> <u>Recap Schedules</u>

INDEX OF CHARTS

COLOR CODE

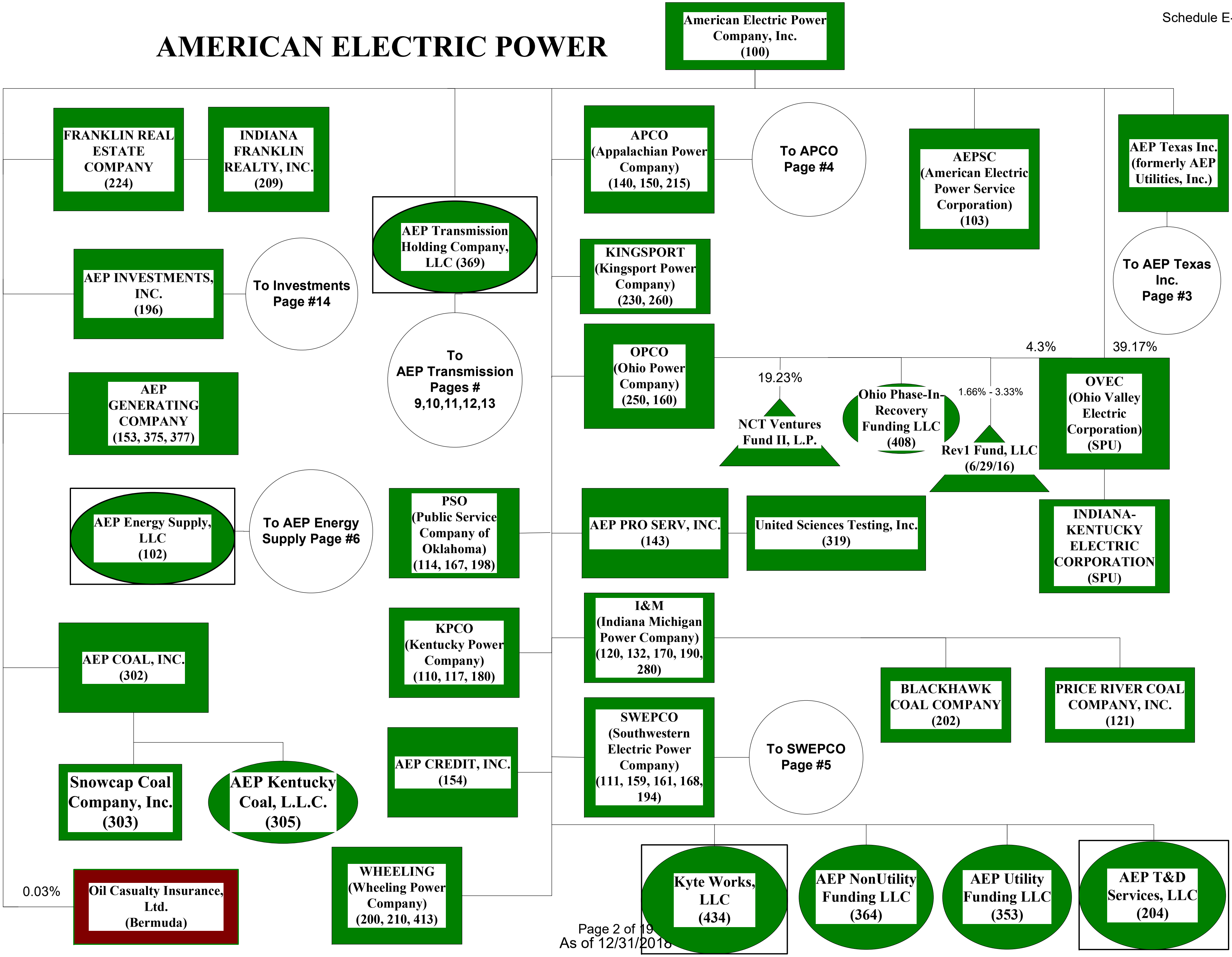
ACTIVE ENTITIES

FOREIGN ENTITY

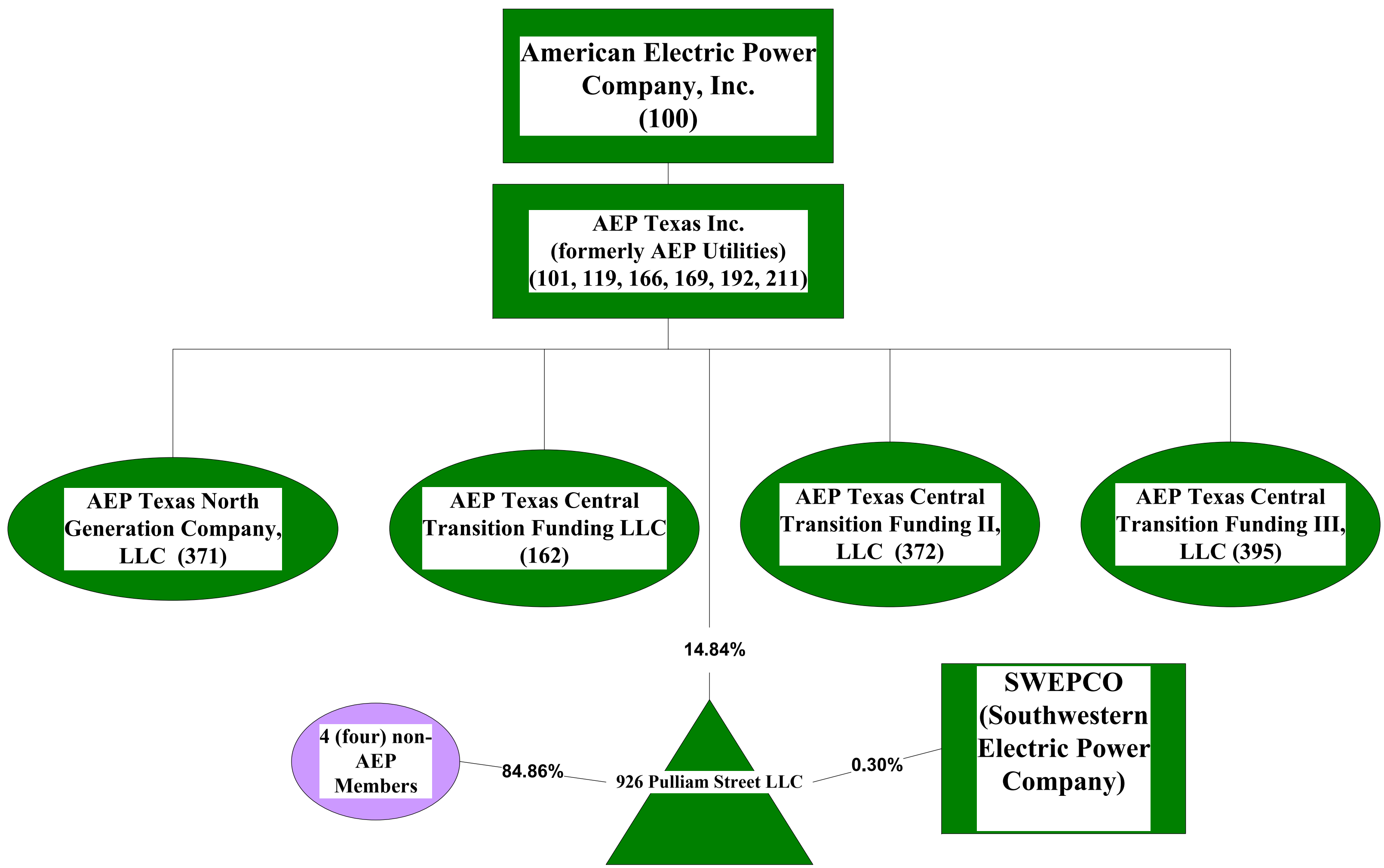
NON-AEP ENTITY

DEFINES A UMBRELLA ENTITY AS IN A DELAWARE SERIES LLC

AMERICAN ELECTRIC POWER



AEP Texas Inc.



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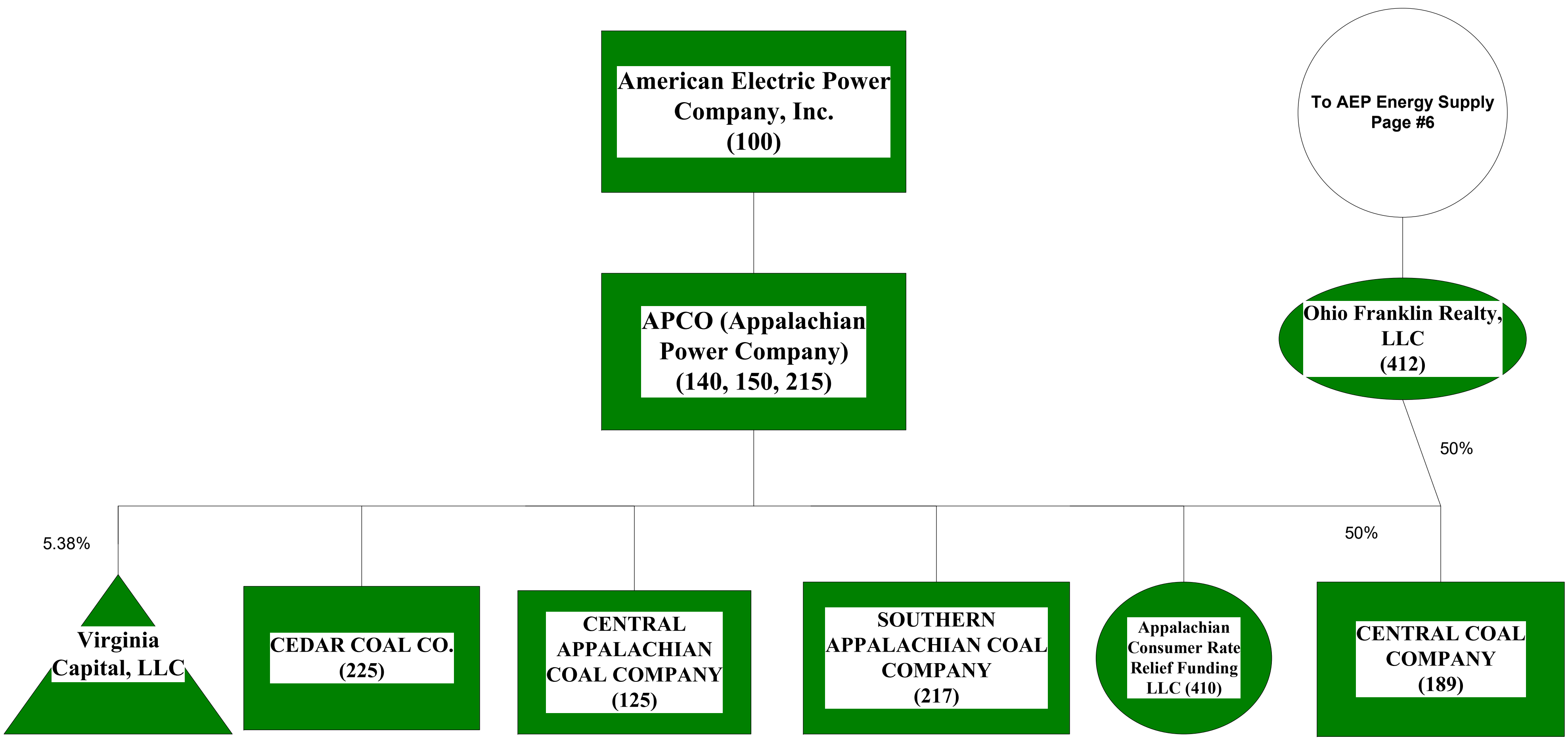
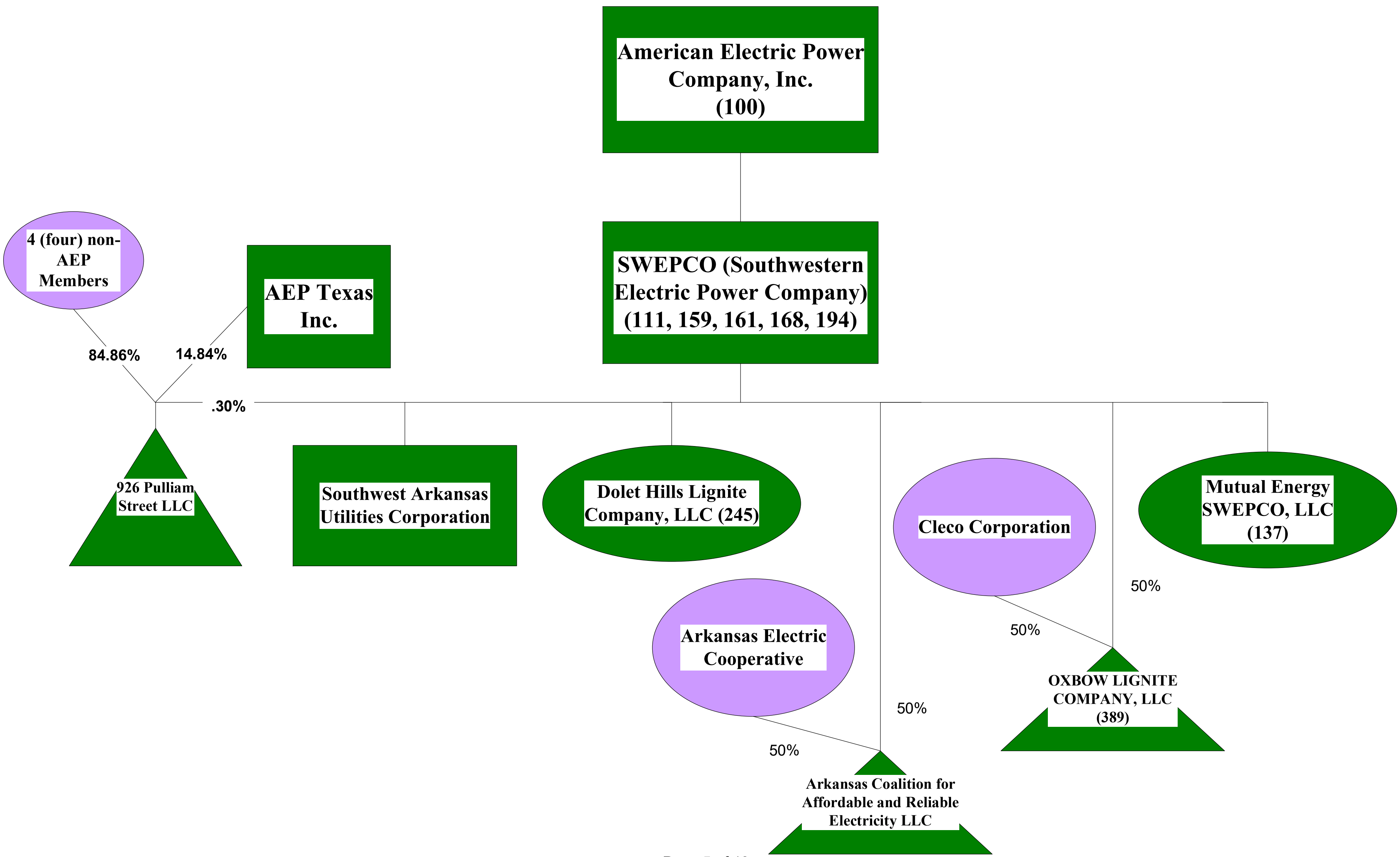
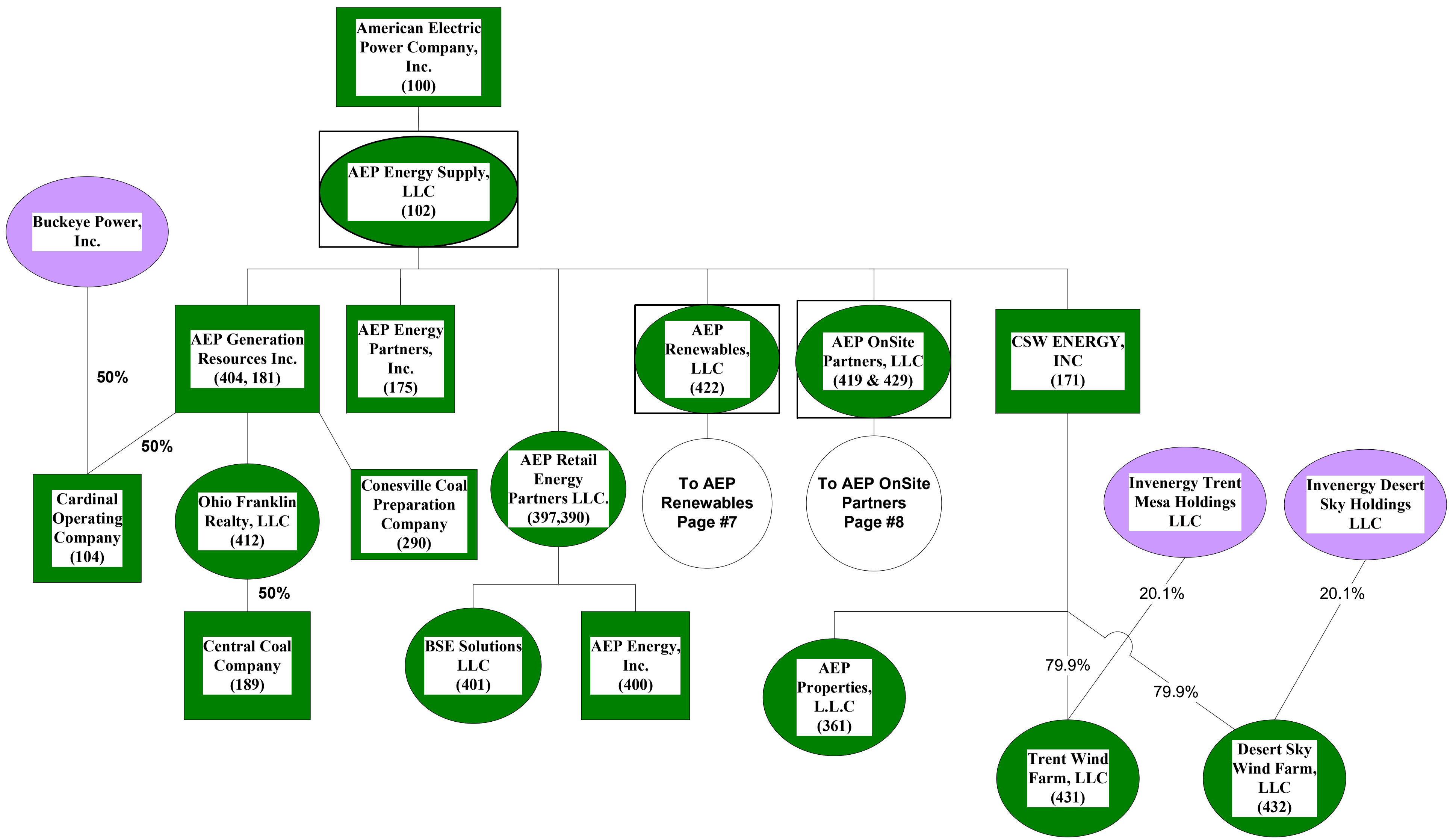


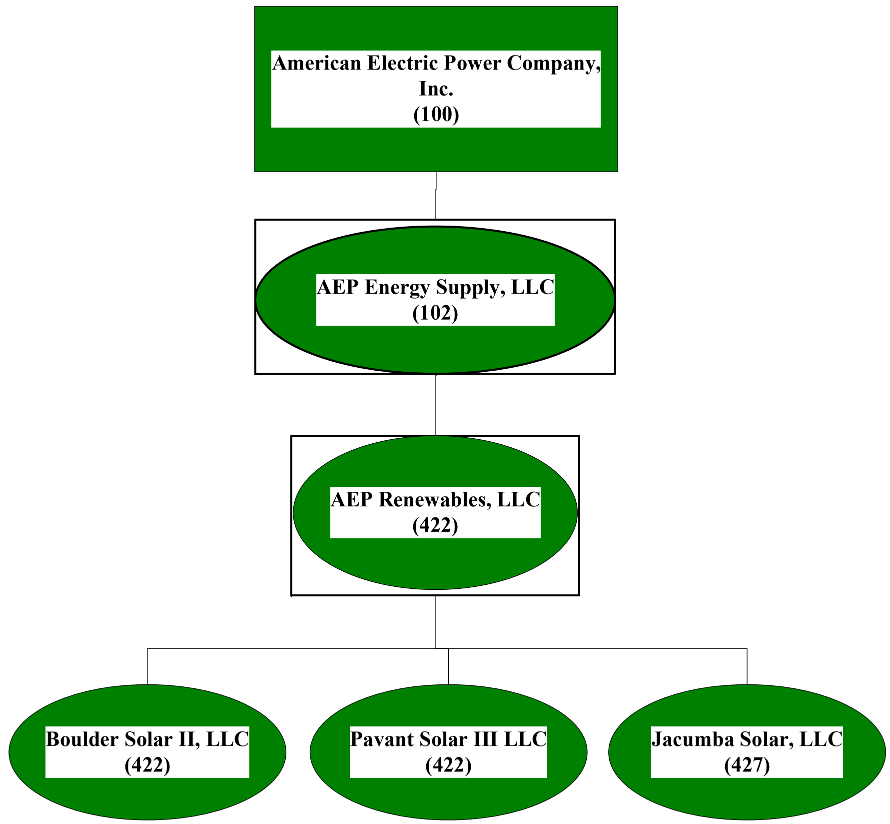
SWEPCO (Southwestern Electric Power Company)



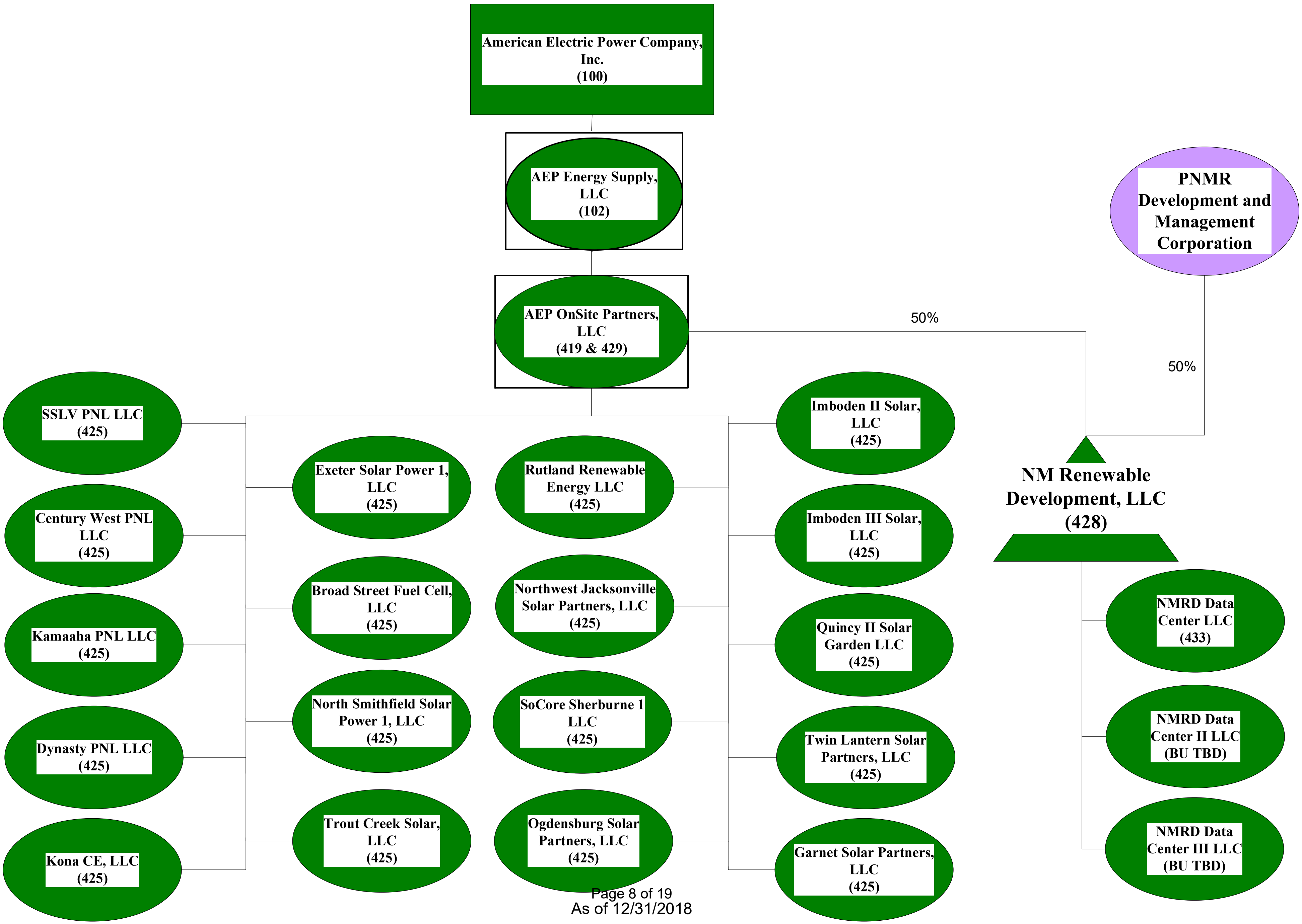
AEP Energy Supply LLC



AEP Energy Supply LLC: AEP Renewables LLC

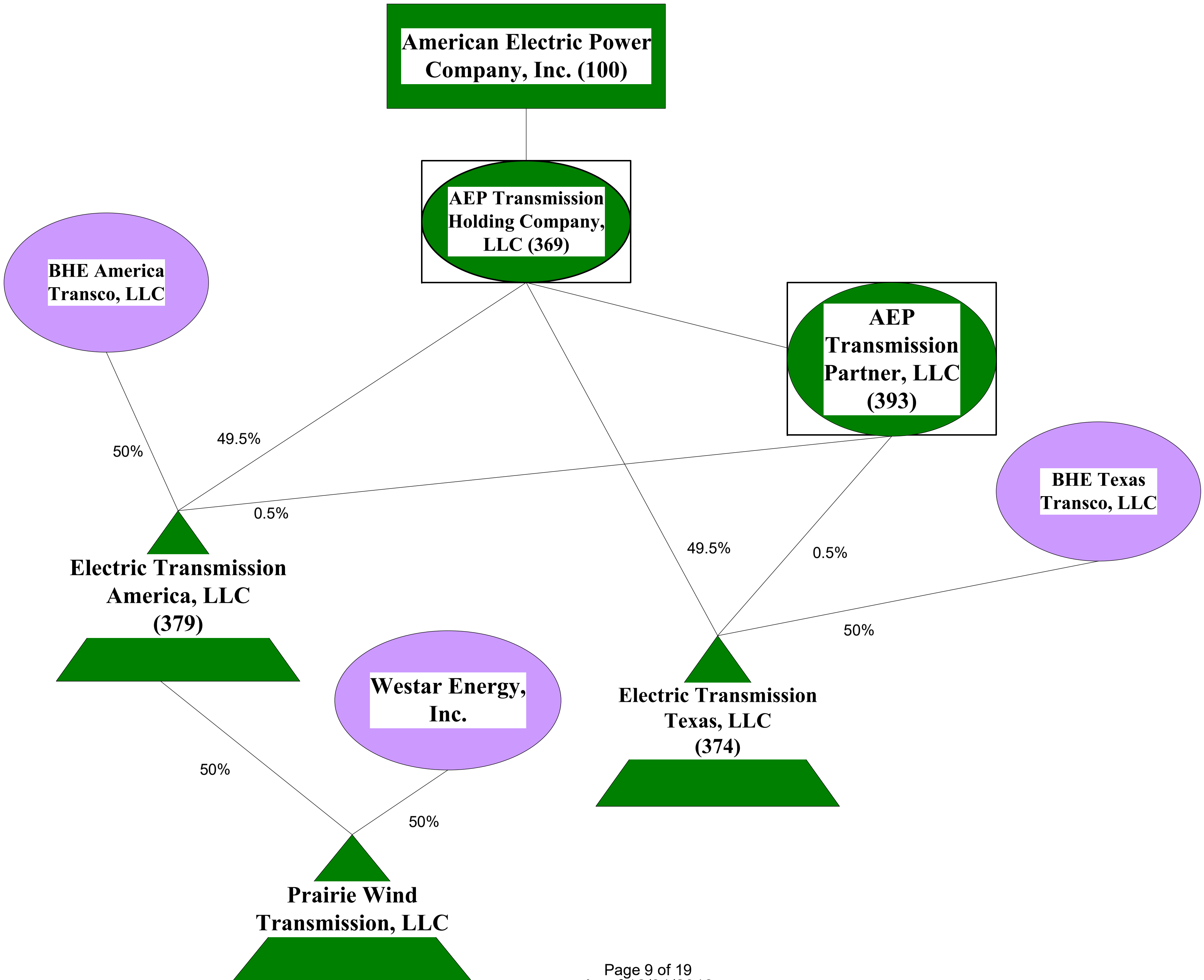


AEP Energy Supply LLC: AEP OnSite Partners LLC

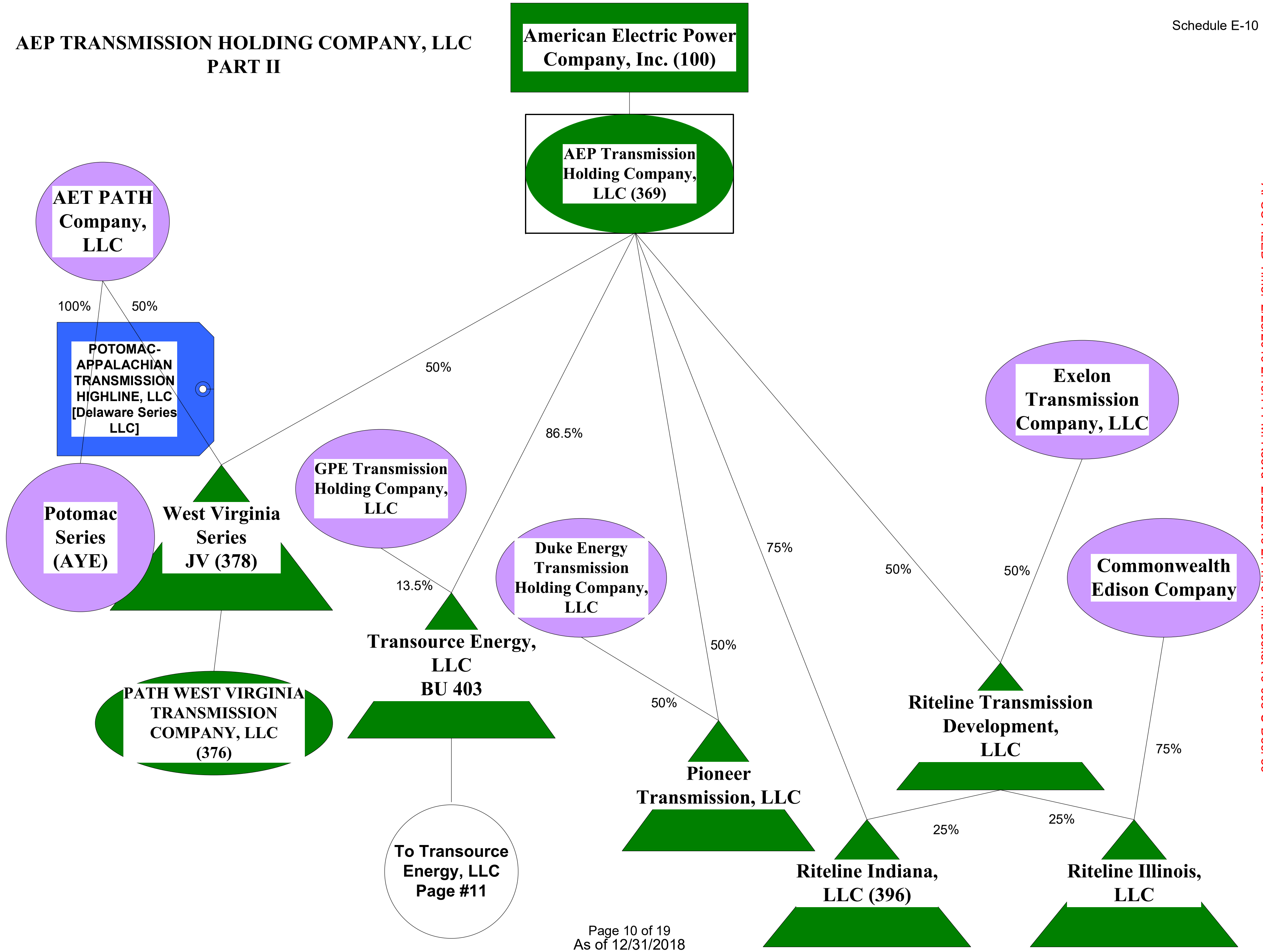


As of 12/31/2018

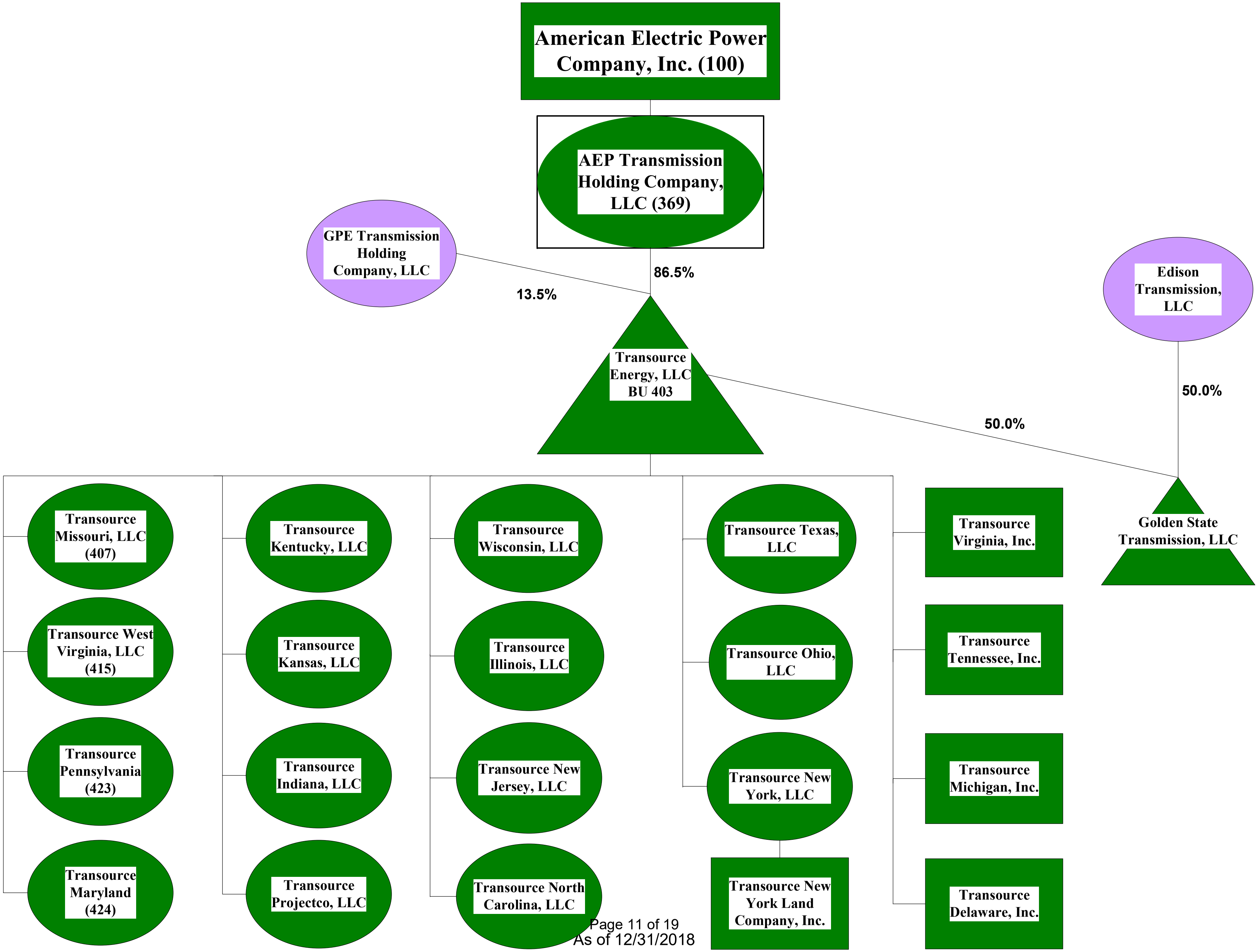
AEP TRANSMISSION HOLDING COMPANY, LLC
PART I: AEP TRANSMISSION PARTNER, LLC



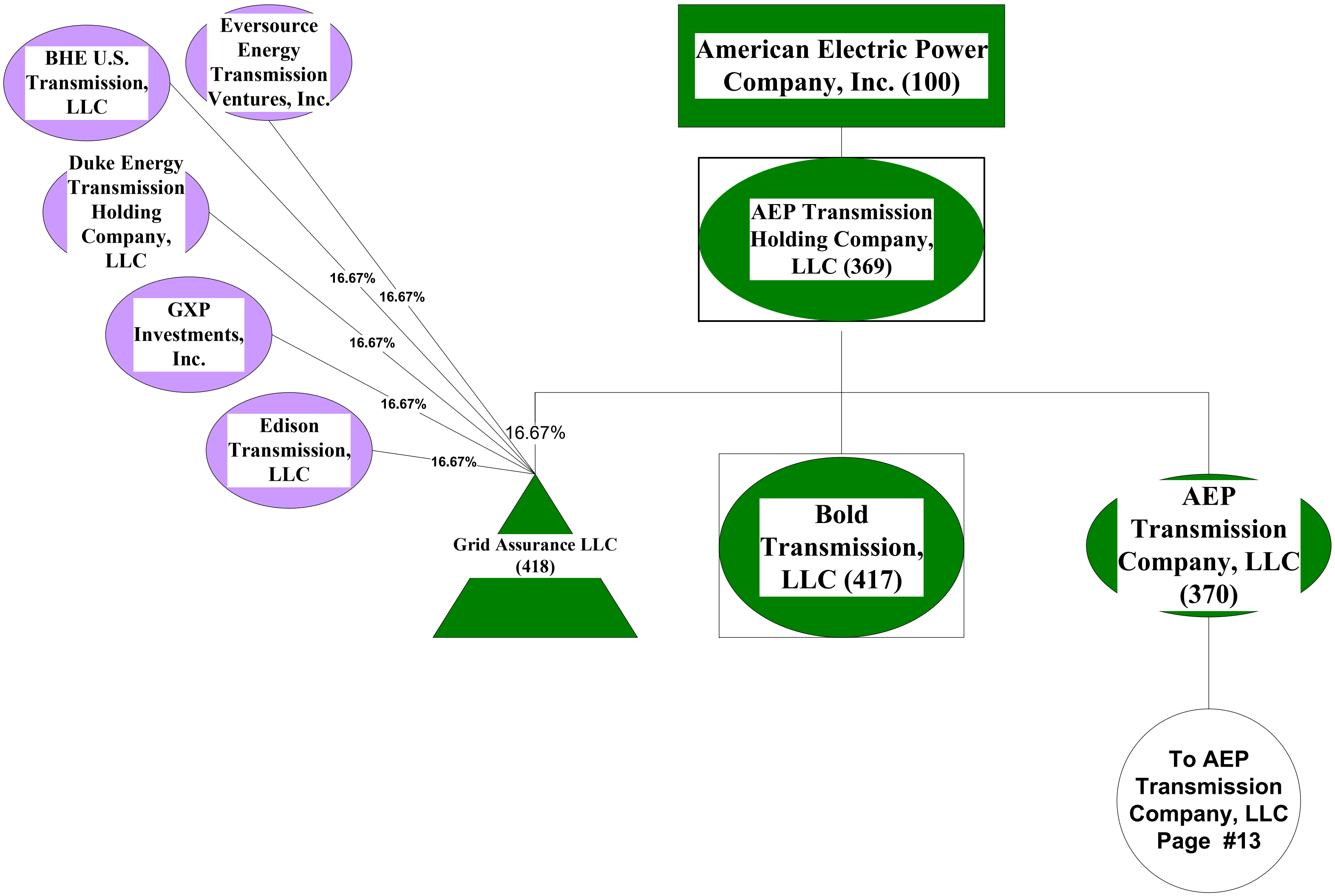
AEP TRANSMISSION HOLDING COMPANY, LLC
PART II



AEP TRANSMISSION HOLDING COMPANY, LLC
PART III: TRANSOURCE ENERGY

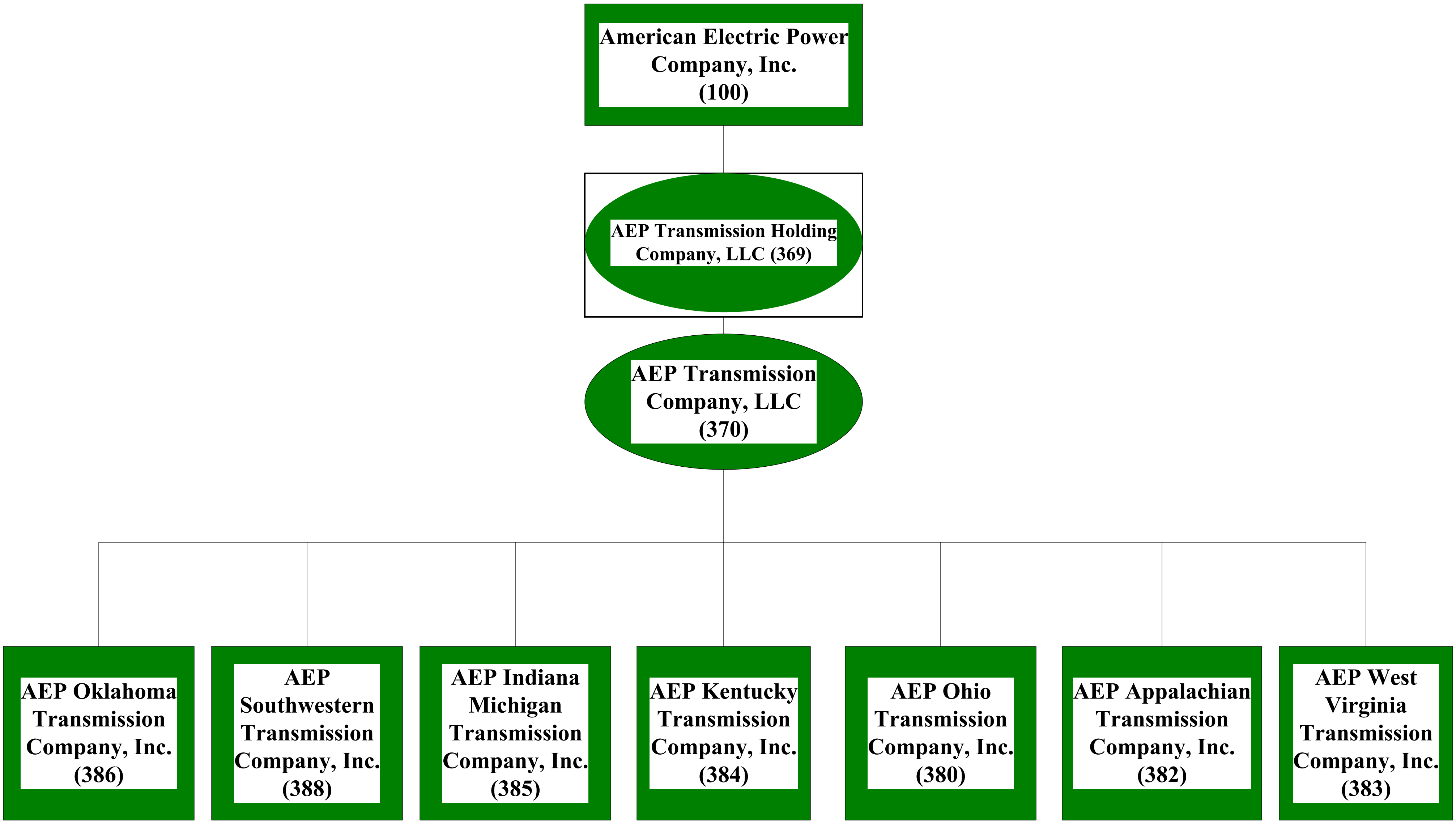


AEP TRANSMISSION HOLDING COMPANY, LLC
PART IV

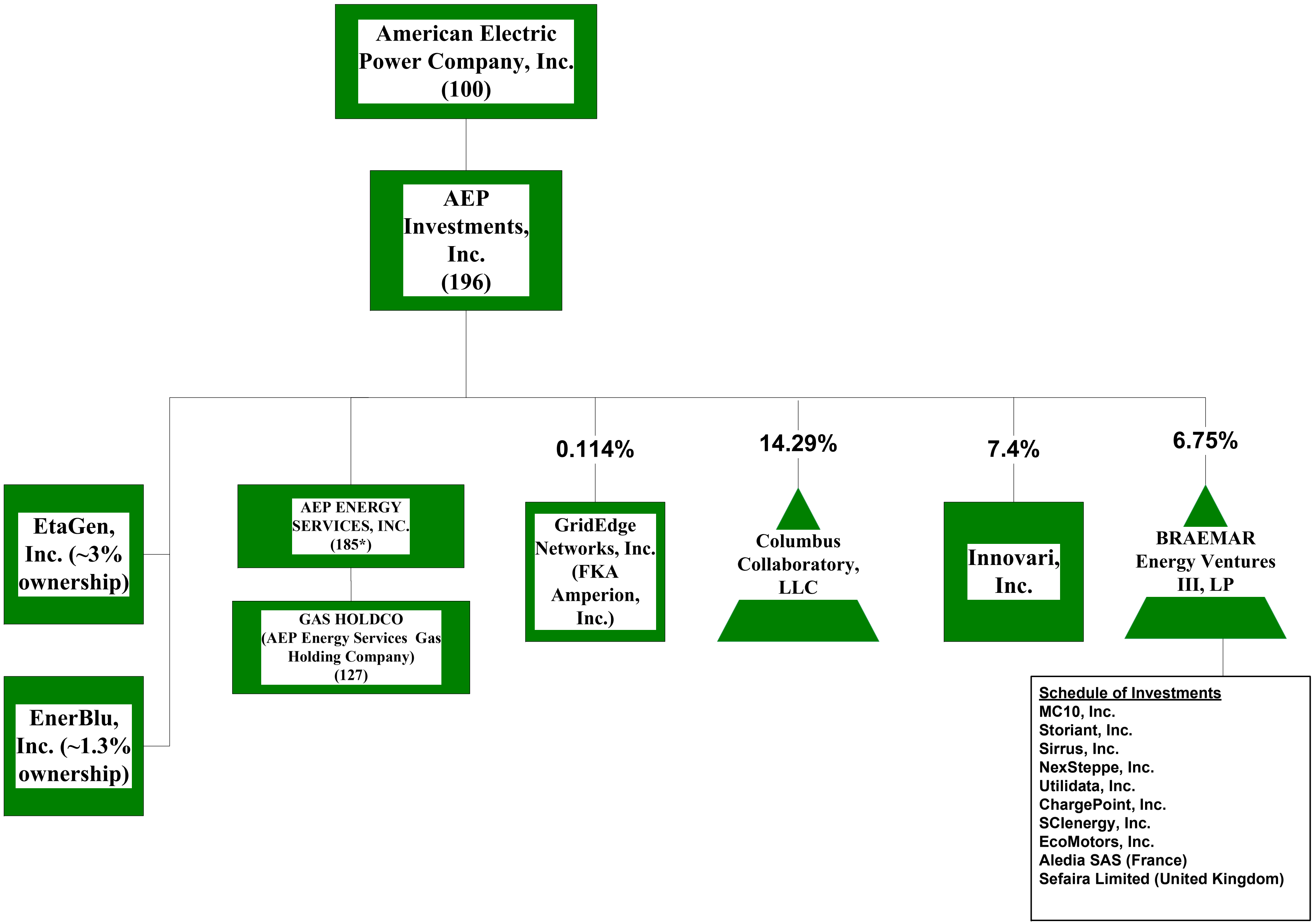


As of 12/31/2018

AEP TRANSMISSION COMPANY, LLC



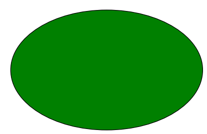
AEP INVESTMENTS, INC.



As of 12/31/2018

Legend / Key - Federal Tax Entity


Association - C-Corp.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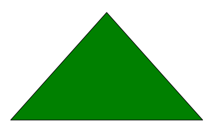
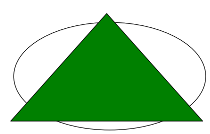
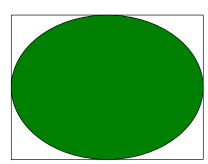

Partnership


Branch - Disregarded Entity


Check the Box Corporation

Southwestern Electric Power Company

- **Smoak, Malcolm** – President & COO
  - **Roth, Carol** – Exec. Admin. Assist.
  - **Sullivan, Carey** – Dir. Communications
    - **Phillips, Cynthia T** – Admn. Asst. Sr.
    - **Main, Peter** – Communications Consult Prin.
    - **Wissing, Karen E** – Communications Consult Sr.
    - **Vacant** – Communications Consult Sr.
  - **Bond, Brian** – VP External Affairs
    - **Warren, Betsy** – External Affairs Coordinator Assoc.
    - **Hardin, Bradley E** – State Gov. Affairs Manager
    - **Gibbs, Gary J** – State Govt. & Env. Affairs Manager
    - **Milford, Jeffery A** – External Affairs Manager
    - **Corbin, Michael D** – External Affairs Manager
    - **Harland, Jennifer** – External Affairs Manager
    - **Robinson, Mark A** – External Affairs Manager
  - **Brice, Tom** – VP Reg. & Finance
    - **Procell, Brenda** – Admn. Asst. Sr.
    - **Ferry-Nelson, Lynn** – Director Regulatory Svcs.
    - **Meyers, Brenda** – Director Business Ops. Support
  - **Seidel, Drew** – VP Distr. Region Ops.
    - **Irle, Charlene** – Admn. Asst. Sr.
    - **Mathews, Michael S** – Mngr. Dist. System
    - **Hopwood, Todd** – Mngr. Dist. System
    - **Blanton, Bryan K** – Mngr. Dist. System
    - **Harland, Craig H** – Mngr. Dist. System
    - **Cain, Richard R** – Mngr. Dist. System
    - **Guin, Gary** – Dir. Risk & Project Management
    - **Vacant** – Continuous Imprvmnt Manager
  - **Vacant** – Dir. Customer Services & Marketing
    - **Liner, Susan** – Cust. Opers. Coord. Sr.
    - **Langston, David** – Cust. Services Manager
    - **Brown, Henry A** – Meter Revenue Opers. Manager
    - **Colvin, Dale** – Cust. Account Mngr. Prin.
    - **Patty, Thomas F** – Cust. Account Mngr. Prin
    - **Andres, Jack W** – Cust. Account Mngr. Prin.
    - **Lawrence, Joey K** – Cust. Account Mngr. Sr.
    - **Mobley, Mark C** – Cust. Account Mngr. Prin.
    - **Tyler, Michael H** – Cust. Account Mngr. Prin.
    - **McCormack, Sherrill** – EE & Consumer Programs Mngr.
    - **Pratt Jr., Paul E** – EE & Consumer Programs Mngr.

American Electric Power Company
Organization Chart

Chairman, Akins, Nicholas K

EVP & Chief Admin Officer	**Hillebrand, Lana L**		
Executive Admin CEO	**Harris, Lorraine R**		
VP Audit Services	**Reis, Andrew B**		
EVP Energy Supply	**Zebula, Charles E**		
EVP General Counsel&Secretary	**Feinberg, David Matthew**		
EVP Generation	**Chodak III, Paul**		
EVP Transmission	**McCullough, Mark C**		
EVP Utilities	**Barton, Lisa M**		
		President & COO - Appalachian	Beam,Christian T
		President & COO - IN/MI	Thomas,Toby L
		President & COO - KY	Mattison, D Brett
		President & COO - OH	Sundararajan, Rajagopalan
		President & COO - PSO	Simmons, Peggy I
		President & COO - SWEPCO	Smoak, Albert M
		President & COO - TX	Talavera, Judith E
		VP Cust Svcs, Mktg & Dist Svcs	Kirkpatrick, Thomas L

American Electric Power Company
Organization Chart

EVP CFO	**Tierney,Brian X**				
	Chief Procurement Officer	Rhoades, Craig T			
	Mng Dir Investor Relations	Rozsa, Bette J			
	SVP Controller & CAO	Buonaiuto, Joseph M			
	SVP Corporate Plnng&Budgeting	Sever Jr., Oliver J			
		Asst Controller	Piatt, Michael Dean		
		Asst Controller	Travis, Frederick S		
		Asst Controller	Williams, Julie		
		Asst Controller Gen&Reg Acctg	Hoersdig, Jeffrey W		
		Asst Controller-Acct Pol&Rsrch	Hunter, Marc B		
		Mng Dir Regulatory Acctg Srvcs	Gregory, Diana L		
				Dir Regulatory Acctg Svcs	Hamlett, Randall W
				Dir Regulatory Acctg Svcs	Ross, Tyler H
				Dir Regulatory Acctg Svcs	Yoder, Jason M
		VP Tax	Llende, James Xavier		
	SVP Strategy & Innovation	Haynes, Stephan T			
	SVP Treasury & Risk	Sloat, Julia A			

American Electric Power Company
Organization Chart

EVP External Affairs — **Patton,Charles R**

Title	Name
Mng Dir Corp Sustaninability	Nessing, Sandra M
Mng Dir RTO Reg & NERC Comp	Snider, Daniel L
SVP & Chief Customer Officer	Evans, Murray Bruce
SVP Corporate Communications	Heydlauff, Dale E
SVP Washington Office	Kavanagh, Anthony P
VP Regulatory Services	Satterwhite, Matthew J
Dir RTO Regulatory - East	Horton, Dana E
Dir RTO Regulatory West	Ross, Charles Richard
Dir Reg Pricing & Analysis	Roush, David M
Dir Regulatory Case Management	Richardson, Annette P
Dir Regulatory Svcs	Duffy, Christopher K
Mng Dir Reg Case Mngmt	Allen, William A
Dir Long Term Markets	Hakimi, A N

SOUTHWESTERN ELECTRIC POWER COMPANY
ARKANSAS JURISDICTIONAL
BILLING DETERMINANTS AND REVENUES
TEST YEAR ENDING DECEMBER 31, 2018

Line No.	Rate Schedule		Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18
1	RESIDENTIAL SERVICE	15							
2	Customer bills		87,105	87,190	87,370	87,486	87,618	87,733	87,999
3	Demand		5,600	5,440	5,288	5,000	5,365	5,392	5,412
4	Usage		98,620,081	83,507,794	64,582,890	58,667,416	59,873,042	94,325,399	109,884,077
5	Usage per Customer		1,132	958	739	671	683	1,075	1,249
6	PB Base Rate Revenue		4,210,543	3,667,426	2,995,128	2,785,204	3,356,451	4,971,490	5,722,378
7	PB Fuel Rider Revenue		3,750,270	2,607,192	1,950,254	1,848,332	2,325,576	2,737,161	3,481,270
8	PB Other Rider Revenue		1,492,902	1,267,745	976,559	888,248	906,611	1,426,745	1,577,218
9	Total PB Retail Sales Revenue		9,453,715	7,542,363	5,921,941	5,521,784	6,588,638	9,135,396	10,780,865
10									
11	RESIDENTIAL-ELECTRIC HTG APPLIANCE	22							
12	Customer bills		13,639	13,526	13,405	13,283	13,159	13,034	12,920
13	Demand		1,770	1,681	1,496	1,315	1,263	1,149	1,123
14	Usage		27,093,010	22,672,034	16,044,180	13,377,784	11,809,074	16,096,396	18,028,397
15	Usage per Customer		1,986	1,676	1,197	1,007	897	1,235	1,395
16	PB Base Rate Revenue		811,517	710,755	549,567	487,226	631,036	836,928	931,406
17	PB Fuel Rider Revenue		1,030,277	707,853	484,504	421,472	458,687	467,089	571,163
18	PB Other Rider Revenue		411,279	341,005	246,216	204,511	180,809	246,385	261,643
19	Total PB Retail Sales Revenue		2,253,072	1,759,614	1,280,287	1,113,209	1,270,531	1,550,403	1,764,212
20									
21	RESIDENTIAL-MULTIPLE DWELLING	38							
22	Customer bills		35	35	35	35	35	35	35
23	Demand		82	82	64	60	47	47	53
24	Usage		50,923	45,355	30,669	28,145	19,264	25,075	31,038
25	Usage per Customer		1,455	1,296	876	804	550	716	887
26	PB Base Rate Revenue		2,083	1,876	1,574	1,275	1,119	1,373	1,634
27	PB Fuel Rider Revenue		1,936	1,416	926	887	748	728	983
28	PB Other Rider Revenue		782	706	260	430	295	386	460
29	Total PB Retail Sales Revenue		4,802	3,998	2,760	2,592	2,162	2,487	3,077
30									
31	RESIDENTIAL-ELECT HT-MULTI DWELLING	39							
32	Customer bills		37	37	37	37	37	37	37
33	Demand		260	363	303	230	226	169	159
34	Usage		90,963	95,784	80,834	73,830	72,624	53,941	53,693
35	Usage per Customer		2,458	2,589	2,185	1,995	1,963	1,458	1,451
36	PB Base Rate Revenue		2,597	2,687	2,357	2,214	3,663	2,752	2,729
37	PB Fuel Rider Revenue		3,459	2,991	2,441	2,326	2,821	1,565	1,701
38	PB Other Rider Revenue		1,396	1,490	1,251	1,127	1,109	825	779
39	Total PB Retail Sales Revenue		7,452	7,168	6,049	5,667	7,593	5,142	5,209
40									
41	MASTER MTRD-GENERAL SERV-YEAR 2	50							
42	Customer bills		5	5	5	5	5	5	5
43	Demand		92	99	68	52	56	68	67
44	Usage		44,913	40,856	31,343	29,459	28,604	39,022	39,733
45	Usage per Customer		8,983	8,171	6,269	5,892	5,721	7,804	7,947
46	PB Base Rate Revenue		1,549	1,469	1,104	998	1,151	1,518	1,535
47	PB Fuel Rider Revenue		1,708	1,276	946	928	1,111	1,132	1,259
48	PB Other Rider Revenue		595	556	423	388	395	532	512
49	Total PB Retail Sales Revenue		3,852	3,301	2,473	2,314	2,657	3,182	3,306
50									
51	MASTER MTRD-LTG & PWR-YR2-SECONDARY	60							
52	Customer bills		2	2	2	2	2	2	2
53	Demand		221	221	221	221	224	224	238
54	Usage		77,600	69,800	57,200	60,600	53,720	97,600	102,920
55	Usage per Customer		38,800	34,900	28,600	30,300	26,860	48,800	51,460
56	PB Base Rate Revenue		1,671	1,623	1,572	1,598	2,517	3,213	3,405
57	PB Fuel Rider Revenue		2,951	2,179	1,727	1,909	2,087	2,832	3,261
58	PB Other Rider Revenue		953	886	751	775	798	1,294	1,299
59	Total PB Retail Sales Revenue		5,575	4,688	4,050	4,283	5,402	7,339	7,965

Line No.	Rate Schedule		Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	12 Month Total
1	RESIDENTIAL SERVICE	15						
2	Customer bills		88,266	88,469	87,016	87,237	87,504	1,050,992
3	Demand		5,463	5,532	5,360	5,286	5,286	64,423
4	Usage		109,730,724	102,613,944	70,830,542	57,483,784	76,132,018	986,251,711
5	Usage per Customer		1,243	1,160	814	659	870	11,253
6	PB Base Rate Revenue		5,640,767	4,503,188	1,693,684	2,720,635	4,627,853	46,894,746
7	PB Fuel Rider Revenue		3,279,303	2,499,633	1,447,685	1,712,360	3,038,156	30,677,193
8	PB Other Rider Revenue		1,696,195	1,361,784	645,994	786,565	1,442,483	14,469,049
9	Total PB Retail Sales Revenue		10,616,265	8,364,606	3,787,362	5,219,559	9,108,492	92,040,987
10								
11	RESIDENTIAL-ELECTRIC HTG APPLIANCE	22						
12	Customer bills		12,822	12,707	14,107	13,971	13,875	160,449
13	Demand		1,137	1,101	1,059	1,150	1,150	15,395
14	Usage		18,090,702	16,934,982	13,445,035	12,458,151	18,608,918	204,658,664
15	Usage per Customer		1,411	1,333	953	892	1,341	15,324
16	PB Base Rate Revenue		920,679	735,005	260,056	471,330	845,091	8,190,597
17	PB Fuel Rider Revenue		540,640	412,529	274,545	371,112	742,611	6,482,481
18	PB Other Rider Revenue		282,878	226,911	123,531	171,635	355,092	3,051,895
19	Total PB Retail Sales Revenue		1,744,197	1,374,445	658,132	1,014,076	1,942,793	17,724,973
20								
21	RESIDENTIAL-MULTIPLE DWELLING	38						
22	Customer bills		39	37	34	31	35	422
23	Demand		51	57	54	56	56	708
24	Usage		29,965	26,847	19,710	21,433	31,324	359,750
25	Usage per Customer		767	725	575	686	888	10,226
26	PB Base Rate Revenue		1,612	1,241	508	1,052	1,888	17,236
27	PB Fuel Rider Revenue		896	654	402	638	1,250	11,465
28	PB Other Rider Revenue		459	360	181	268	598	5,184
29	Total PB Retail Sales Revenue		2,966	2,255	1,092	1,959	3,736	33,885
30								
31	RESIDENTIAL-ELECT HT-MULTI DWELLING	39						
32	Customer bills		37	37	37	37	37	445
33	Demand		161	214	220	190	190	2,685
34	Usage		54,113	78,721	70,696	60,360	74,778	860,337
35	Usage per Customer		1,459	2,127	1,896	1,619	2,005	23,205
36	PB Base Rate Revenue		2,708	3,315	1,128	1,899	3,050	31,099
37	PB Fuel Rider Revenue		1,617	1,918	1,444	1,798	2,984	27,064
38	PB Other Rider Revenue		846	1,053	648	831	1,426	12,780
39	Total PB Retail Sales Revenue		5,171	6,286	3,220	4,528	7,460	70,944
40								
41	MASTER MTRD-GENERAL SERV-YEAR 2	50						
42	Customer bills		5	5	5	5	5	60
43	Demand		66	68	68	45	45	794
44	Usage		40,667	42,451	35,203	27,515	33,389	433,155
45	Usage per Customer		8,116	8,488	6,985	5,461	6,626	86,462
46	PB Base Rate Revenue		1,554	1,371	622	941	1,515	15,326
47	PB Fuel Rider Revenue		1,215	1,034	719	820	1,332	13,481
48	PB Other Rider Revenue		566	505	276	328	550	5,627
49	Total PB Retail Sales Revenue		3,336	2,910	1,617	2,088	3,397	34,433
50								
51	MASTER MTRD-LTG & PWR-YR2-SECONDARY	60						
52	Customer bills		2	2	2	2	2	24
53	Demand		240	268	230	203	203	2,712
54	Usage		99,468	107,006	81,201	57,555	61,943	926,613
55	Usage per Customer		49,629	53,487	40,280	28,559	30,730	462,404
56	PB Base Rate Revenue		3,420	3,178	969	1,799	2,326	27,291
57	PB Fuel Rider Revenue		2,973	2,607	1,658	1,714	2,472	28,370
58	PB Other Rider Revenue		1,373	1,266	594	689	1,003	11,680
59	Total PB Retail Sales Revenue		7,766	7,050	3,221	4,202	5,801	67,341

SOUTHWESTERN ELECTRIC POWER COMPANY
ARKANSAS JURISDICTIONAL
BILLING DETERMINANTS AND REVENUES
TEST YEAR ENDING DECEMBER 31, 2018

Line No.	Rate Schedule		Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18
60									
61	RESIDENTIAL NET-METERING	62							
62	Customer bills		54	58	58	56	61	58	60
63	Demand		-	-	-	-	-	-	-
64	Usage		54,907	47,289	37,209	29,302	27,636	44,328	51,041
65	Usage per Customer		1,017	815	642	523	453	764	851
66	PB Base Rate Revenue		2,325	2,118	1,762	1,476	1,809	2,544	2,870
67	PB Fuel Rider Revenue		2,088	1,476	1,124	923	1,074	1,286	1,617
68	PB Other Rider Revenue		892	730	579	452	389	685	727
69	Total PB Retail Sales Revenue		5,305	4,324	3,464	2,851	3,271	4,516	5,214
70									
71	MASTER MTRD-LTG & PWR-YR 2-PRIMARY	66							
72	Customer bills		2	2	2	2	2	2	2
73	Demand		713	1,194	867	867	882	900	906
74	Usage		273,600	246,480	135,720	113,040	115,320	199,320	213,120
75	Usage per Customer		136,800	123,240	67,860	56,520	57,660	99,660	106,560
76	PB Base Rate Revenue		4,980	7,391	5,190	5,116	7,770	9,193	9,452
77	PB Fuel Rider Revenue		10,076	7,453	3,969	3,449	4,338	5,602	6,539
78	PB Other Rider Revenue		3,188	3,205	1,877	1,621	1,902	2,861	2,843
79	Total PB Retail Sales Revenue		18,244	18,049	11,037	10,186	14,010	17,655	18,834
80									
81	8000L MV PL ON EXISTING POLE	91							
82	Customer bills		2,413	2,401	2,386	2,383	2,360	2,350	2,352
83	Demand		-	-	-	-	-	-	-
84	Usage		162,774	161,870	160,193	159,839	159,462	158,808	158,134
85	Usage per Customer		67	67	67	67	68	68	67
86	PB Base Rate Revenue		15,140	15,068	14,916	14,824	14,810	14,772	14,359
87	PB Fuel Rider Revenue		6,198	5,058	4,845	5,029	6,187	4,601	5,003
88	PB Other Rider Revenue		270	260	272	284	292	265	254
89	Total PB Retail Sales Revenue		21,608	20,385	20,033	20,137	21,289	19,638	19,616
90									
91	8000L MV PL ON WOOD POLE	92							
92	Customer bills		870	859	834	863	852	845	801
93	Demand		-	-	-	-	-	-	-
94	Usage		58,727	57,876	56,031	57,922	57,221	56,938	53,125
95	Usage per Customer		68	67	67	67	67	67	66
96	PB Base Rate Revenue		12,260	12,057	11,691	12,098	11,944	11,897	11,071
97	PB Fuel Rider Revenue		2,237	1,808	1,699	1,823	2,221	1,650	1,686
98	PB Other Rider Revenue		185	207	187	180	182	182	173
99	Total PB Retail Sales Revenue		14,682	14,072	13,578	14,101	14,347	13,729	12,930
100									
101	175W MV OUTDOOR LIGHTING	93							
102	Customer bills		260	254	250	251	249	249	250
103	Demand		-	-	-	-	-	-	-
104	Usage		17,057	17,087	16,975	16,948	16,864	16,711	16,659
105	Usage per Customer		66	67	68	68	68	67	67
106	PB Base Rate Revenue		3,905	3,900	3,878	3,868	3,845	3,780	3,768
107	PB Fuel Rider Revenue		649	534	513	533	654	484	527
108	PB Other Rider Revenue		23	23	23	23	24	24	22
109	Total PB Retail Sales Revenue		4,577	4,457	4,415	4,424	4,524	4,289	4,317
110									
111	100W MV AREA LIGHTING	94							
112	Customer bills		3	3	3	3	3	3	3
113	Demand		-	-	-	-	-	-	-
114	Usage		126	126	126	126	126	126	126
115	Usage per Customer		42	42	42	42	42	42	42
116	PB Base Rate Revenue		46	46	46	46	46	46	46
117	PB Fuel Rider Revenue		5	4	4	4	5	4	4
118	PB Other Rider Revenue		-	-	-	-	-	-	-
119	Total PB Retail Sales Revenue		51	50	50	50	51	50	50

Line No.	Rate Schedule		Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	12 Month Total
60								
61	RESIDENTIAL NET-METERING	62						
62	Customer bills		59	60	46	49	53	673
63	Demand		-	-	-	-	-	-
64	Usage		60,217	58,988	29,049	24,653	35,903	500,521
65	Usage per Customer		1,018	983	627	499	672	8,864
66	PB Base Rate Revenue		3,239	2,700	716	1,227	2,292	25,076
67	PB Fuel Rider Revenue		1,800	1,437	593	734	1,433	15,585
68	PB Other Rider Revenue		947	788	286	367	706	7,550
69	Total PB Retail Sales Revenue		5,985	4,925	1,595	2,329	4,431	48,210
70								
71	MASTER MTRD-LTG & PWR-YR 2-PRIMARY	66						
72	Customer bills		2	3	2	2	2	25
73	Demand		900	2,088	132	101	101	9,653
74	Usage		299,298	304,994	164,521	113,021	148,237	2,326,671
75	Usage per Customer		149,333	101,633	81,610	56,082	73,540	1,110,499
76	PB Base Rate Revenue		10,952	17,970	2,391	4,287	6,462	91,155
77	PB Fuel Rider Revenue		8,663	7,195	3,254	3,261	5,729	69,528
78	PB Other Rider Revenue		4,115	665	1,232	1,392	2,420	27,319
79	Total PB Retail Sales Revenue		23,729	25,830	6,877	8,940	14,611	188,002
80								
81	8000L MV PL ON EXISTING POLE	91						
82	Customer bills		2,333	2,309	2,308	2,296	2,296	28,187
83	Demand		-	-	-	-	-	-
84	Usage		165,214	162,625	158,484	167,989	175,561	1,950,953
85	Usage per Customer		71	70	69	73	76	831
86	PB Base Rate Revenue		14,978	12,939	8,319	15,835	20,334	176,292
87	PB Fuel Rider Revenue		4,914	4,070	3,559	5,217	6,468	61,149
88	PB Other Rider Revenue		917	746	600	724	992	5,876
89	Total PB Retail Sales Revenue		20,809	17,754	12,478	21,776	27,795	243,317
90								
91	8000L MV PL ON WOOD POLE	92						
92	Customer bills		831	824	829	810	810	10,028
93	Demand		-	-	-	-	-	-
94	Usage		56,078	57,549	57,504	60,776	63,236	692,984
95	Usage per Customer		67	70	69	75	78	830
96	PB Base Rate Revenue		11,352	10,362	6,945	13,055	16,096	140,827
97	PB Fuel Rider Revenue		1,668	1,456	1,335	1,915	2,252	21,751
98	PB Other Rider Revenue		658	531	423	498	711	4,119
99	Total PB Retail Sales Revenue		13,678	12,349	8,703	15,468	19,060	166,698
100								
101	175W MV OUTDOOR LIGHTING	93						
102	Customer bills		243	244	245	245	245	2,985
103	Demand		-	-	-	-	-	-
104	Usage		17,378	17,219	16,539	17,702	18,815	205,955
105	Usage per Customer		72	71	68	72	77	828
106	PB Base Rate Revenue		3,848	3,324	2,107	4,088	5,434	45,746
107	PB Fuel Rider Revenue		517	429	366	546	703	6,457
108	PB Other Rider Revenue		39	32	22	30	45	331
109	Total PB Retail Sales Revenue		4,404	3,785	2,495	4,664	6,182	52,534
110								
111	100W MV AREA LIGHTING	94						
112	Customer bills		3	3	3	3	3	36
113	Demand		-	-	-	-	-	-
114	Usage		134	132	119	127	139	1,534
115	Usage per Customer		45	44	40	42	46	511
116	PB Base Rate Revenue		48	41	23	46	68	550
117	PB Fuel Rider Revenue		4	3	2	4	6	48
118	PB Other Rider Revenue		-	-	-	-	-	-
119	Total PB Retail Sales Revenue		52	44	26	50	74	598

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Line No.	Rate Schedule		Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18
120									
121	400W MV OUTDOOR LIGHTING	95							
122	Customer bills		8	8	8	8	8	8	8
123	Demand		-	-	-	-	-	-	-
124	Usage		1,240	1,240	1,240	1,240	1,240	1,240	1,240
125	Usage per Customer		155	155	155	155	155	155	155
126	PB Base Rate Revenue		131	131	131	131	131	131	130
127	PB Fuel Rider Revenue		47	39	38	39	48	36	39
128	PB Other Rider Revenue		-	-	-	-	-	-	-
129	Total PB Retail Sales Revenue		178	169	168	170	179	167	169
130									
131	400W MV AREA LIGHTING	96							
132	Customer bills		71	71	71	71	70	71	70
133	Demand		-	-	-	-	-	-	-
134	Usage		11,005	11,005	10,860	10,854	10,850	10,963	10,731
135	Usage per Customer		155	155	153	153	155	154	153
136	PB Base Rate Revenue		1,082	1,082	1,070	1,069	1,069	1,078	1,075
137	PB Fuel Rider Revenue		420	344	328	342	422	318	340
138	PB Other Rider Revenue		12	12	12	12	12	12	11
139	Total PB Retail Sales Revenue		1,513	1,438	1,411	1,423	1,503	1,408	1,427
140									
141	100W HPS OUTDOOR LIGHTING	97							
142	Customer bills		3,561	3,612	3,588	3,593	3,651	3,640	3,659
143	Demand		-	-	-	-	-	-	-
144	Usage		172,881	175,087	174,009	174,490	176,728	177,146	177,790
145	Usage per Customer		49	48	48	49	48	49	49
146	PB Base Rate Revenue		44,858	45,370	44,780	45,211	45,790	45,928	46,002
147	PB Fuel Rider Revenue		6,596	5,479	5,273	5,506	6,874	5,145	5,639
148	PB Other Rider Revenue		228	240	344	275	217	217	208
149	Total PB Retail Sales Revenue		51,683	51,090	50,397	50,992	52,880	51,290	51,849
150									
151	100W HPS AREA LIGHTING	98							
152	Customer bills		2,521	2,540	2,483	2,480	2,470	2,490	2,497
153	Demand		-	-	-	-	-	-	-
154	Usage		122,394	122,213	119,124	120,775	120,723	121,075	121,280
155	Usage per Customer		49	48	48	49	49	49	49
156	PB Base Rate Revenue		33,005	32,987	32,373	32,581	32,598	32,651	32,607
157	PB Fuel Rider Revenue		4,668	3,824	3,613	3,809	4,696	3,517	3,847
158	PB Other Rider Revenue		278	271	278	310	275	306	310
159	Total PB Retail Sales Revenue		37,951	37,082	36,265	36,701	37,568	36,474	36,763
160									
161	250W HPS OUTDOOR LIGHTING	103							
162	Customer bills		125	126	126	127	125	125	128
163	Demand		-	-	-	-	-	-	-
164	Usage		13,125	13,209	13,230	13,189	13,054	13,125	13,351
165	Usage per Customer		105	105	105	104	104	105	104
166	PB Base Rate Revenue		2,470	2,485	2,487	2,482	2,461	2,471	2,503
167	PB Fuel Rider Revenue		500	412	400	416	507	381	423
168	PB Other Rider Revenue		17	17	18	17	17	17	16
169	Total PB Retail Sales Revenue		2,988	2,913	2,904	2,915	2,986	2,869	2,943
170									
171	250W HPS AREA LIGHTING	104							
172	Customer bills		78	78	79	79	78	78	78
173	Demand		-	-	-	-	-	-	-
174	Usage		8,190	8,190	8,197	8,185	8,190	8,190	8,190
175	Usage per Customer		105	105	104	104	105	105	105
176	PB Base Rate Revenue		1,296	1,297	1,298	1,296	1,256	1,293	1,290
177	PB Fuel Rider Revenue		312	256	248	258	319	238	260
178	PB Other Rider Revenue		14	14	14	14	55	18	17
179	Total PB Retail Sales Revenue		1,622	1,567	1,561	1,568	1,629	1,548	1,566

Line No.	Rate Schedule		Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	12 Month Total
120								
121	400W MV OUTDOOR LIGHTING	95						
122	Customer bills		8	8	8	9	9	98
123	Demand		-	-	-	-	-	-
124	Usage		1,279	1,276	1,198	1,276	1,283	14,991
125	Usage per Customer		160	160	150	142	143	1,838
126	PB Base Rate Revenue		129	120	79	143	145	1,530
127	PB Fuel Rider Revenue		38	34	31	42	39	471
128	PB Other Rider Revenue		-	-	-	-	-	-
129	Total PB Retail Sales Revenue		166	154	110	186	184	2,000
130								
131	400W MV AREA LIGHTING	96						
132	Customer bills		69	69	69	65	65	832
133	Demand		-	-	-	-	-	-
134	Usage		11,049	10,926	11,193	11,161	11,372	131,968
135	Usage per Customer		160	158	162	172	175	1,906
136	PB Base Rate Revenue		1,071	964	731	1,182	1,195	12,668
137	PB Fuel Rider Revenue		333	287	299	374	349	4,157
138	PB Other Rider Revenue		43	35	27	31	46	264
139	Total PB Retail Sales Revenue		1,447	1,287	1,057	1,587	1,589	17,088
140								
141	100W HPS OUTDOOR LIGHTING	97						
142	Customer bills		3,702	3,725	3,695	3,743	3,743	43,912
143	Demand		-	-	-	-	-	-
144	Usage		188,955	188,705	162,716	173,451	187,353	2,129,310
145	Usage per Customer		51	51	44	46	50	582
146	PB Base Rate Revenue		47,640	39,955	23,885	45,828	60,535	535,782
147	PB Fuel Rider Revenue		5,636	4,719	3,630	5,374	6,985	66,856
148	PB Other Rider Revenue		674	2,701	386	445	665	6,599
149	Total PB Retail Sales Revenue		53,949	47,375	27,900	51,647	68,186	609,237
150								
151	100W HPS AREA LIGHTING	98						
152	Customer bills		2,478	2,485	2,475	2,466	2,466	29,851
153	Demand		-	-	-	-	-	-
154	Usage		127,155	125,939	117,675	123,003	133,456	1,474,811
155	Usage per Customer		51	51	48	50	54	593
156	PB Base Rate Revenue		33,423	29,048	18,199	33,941	44,786	388,199
157	PB Fuel Rider Revenue		3,805	3,152	2,644	3,825	4,949	46,349
158	PB Other Rider Revenue		724	520	407	501	778	4,960
159	Total PB Retail Sales Revenue		37,952	32,721	21,250	38,267	50,514	439,509
160								
161	250W HPS OUTDOOR LIGHTING	103						
162	Customer bills		127	126	128	131	131	1,525
163	Demand		-	-	-	-	-	-
164	Usage		13,809	13,823	12,319	13,126	13,779	159,139
165	Usage per Customer		109	110	96	100	105	1,252
166	PB Base Rate Revenue		2,508	2,290	1,416	2,608	2,968	29,149
167	PB Fuel Rider Revenue		410	357	306	426	457	4,995
168	PB Other Rider Revenue		36	30	22	28	41	276
169	Total PB Retail Sales Revenue		2,954	2,676	1,744	3,061	3,466	34,420
170								
171	250W HPS AREA LIGHTING	104						
172	Customer bills		78	78	78	78	78	938
173	Demand		-	-	-	-	-	-
174	Usage		8,489	8,423	7,913	8,399	8,553	99,109
175	Usage per Customer		109	108	101	108	110	1,268
176	PB Base Rate Revenue		1,300	1,178	795	1,416	1,494	15,209
177	PB Fuel Rider Revenue		254	220	204	277	273	3,116
178	PB Other Rider Revenue		56	45	26	31	45	349
179	Total PB Retail Sales Revenue		1,609	1,443	1,025	1,724	1,812	18,674

SOUTHWESTERN ELECTRIC POWER COMPANY
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Line No.	Rate Schedule		Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18
180									
181	400W HPS OUTDOOR LIGHTING	107							
182	Customer bills		853	854	859	861	872	867	871
183	Demand		-	-	-	-	-	-	-
184	Usage		139,685	140,385	139,507	141,633	143,482	142,917	143,306
185	Usage per Customer		164	164	162	164	165	165	165
186	PB Base Rate Revenue		17,441	17,578	17,488	17,754	18,060	17,996	18,003
187	PB Fuel Rider Revenue		5,323	4,384	4,222	4,466	5,583	4,149	4,544
188	PB Other Rider Revenue		159	154	156	154	159	157	147
189	Total PB Retail Sales Revenue		22,922	22,117	21,866	22,374	23,802	22,302	22,694
190									
191	400W HPS AREA LIGHTING	108							
192	Customer bills		1,034	1,033	1,032	1,033	1,031	1,035	1,034
193	Demand		-	-	-	-	-	-	-
194	Usage		170,064	169,851	169,709	170,290	169,831	168,280	169,418
195	Usage per Customer		164	164	164	165	165	163	164
196	PB Base Rate Revenue		22,214	22,197	22,176	22,264	21,961	22,089	22,118
197	PB Fuel Rider Revenue		6,483	5,305	5,132	5,370	6,611	4,886	5,373
198	PB Other Rider Revenue		461	460	483	477	745	475	455
199	Total PB Retail Sales Revenue		29,159	27,961	27,792	28,111	29,316	27,450	27,946
200									
201	1000W HPS OUTDOOR LIGHTING	111							
202	Customer bills		594	601	602	606	613	578	614
203	Demand		-	-	-	-	-	-	-
204	Usage		230,422	230,842	233,393	233,974	237,025	221,944	236,184
205	Usage per Customer		388	384	388	386	387	384	385
206	PB Base Rate Revenue		16,235	16,039	16,406	16,479	16,738	15,825	16,658
207	PB Fuel Rider Revenue		8,785	7,208	7,058	7,379	9,228	6,471	7,491
208	PB Other Rider Revenue		174	176	196	183	183	183	177
209	Total PB Retail Sales Revenue		25,194	23,423	23,661	24,041	26,149	22,479	24,326
210									
211	1000W HPS AREA LIGHTING	112							
212	Customer bills		671	668	676	662	651	610	649
213	Demand		-	-	-	-	-	-	-
214	Usage		259,167	258,496	258,581	256,252	251,539	236,925	251,281
215	Usage per Customer		386	387	383	387	386	388	387
216	PB Base Rate Revenue		20,381	20,325	20,364	20,170	19,847	18,736	19,773
217	PB Fuel Rider Revenue		9,886	8,073	7,821	8,084	9,796	6,906	7,971
218	PB Other Rider Revenue		413	418	408	412	413	409	395
219	Total PB Retail Sales Revenue		30,680	28,815	28,593	28,666	30,056	26,051	28,139
220									
221	70W HPS AREA LIGHTING	115							
222	Customer bills		1	1	1	1	1	1	1
223	Demand		-	-	-	-	-	-	-
224	Usage		35	35	35	35	35	35	35
225	Usage per Customer		35	35	35	35	35	35	35
226	PB Base Rate Revenue		12	12	12	12	12	12	12
227	PB Fuel Rider Revenue		1	1	1	1	1	1	1
228	PB Other Rider Revenue		-	-	-	-	-	-	-
229	Total PB Retail Sales Revenue		13	13	13	13	13	13	13
230									
231	400W MH AREA LIGHTING	132							
232	Customer bills		740	840	842	841	820	823	814
233	Demand		-	-	-	-	-	-	-
234	Usage		115,128	130,817	130,064	128,640	127,706	125,451	126,770
235	Usage per Customer		156	156	154	153	156	152	156
236	PB Base Rate Revenue		14,743	16,681	16,592	16,370	16,247	15,986	16,070
237	PB Fuel Rider Revenue		4,404	4,084	3,933	4,056	4,970	3,642	4,020
238	PB Other Rider Revenue		205	161	183	174	173	173	198
239	Total PB Retail Sales Revenue		19,351	20,926	20,708	20,600	21,390	19,801	20,288
240									

Line No.	Rate Schedule		Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	12 Month Total
180								
181	400W HPS OUTDOOR LIGHTING	107						
182	Customer bills		872	878	888	899	899	10,473
183	Demand		-	-	-	-	-	-
184	Usage		147,755	148,315	130,087	140,445	144,785	1,702,302
185	Usage per Customer		169	169	146	156	161	1,951
186	PB Base Rate Revenue		18,016	16,612	10,201	18,465	19,935	207,550
187	PB Fuel Rider Revenue		4,396	3,884	3,355	4,642	4,569	53,517
188	PB Other Rider Revenue		360	259	304	359	528	2,897
189	Total PB Retail Sales Revenue		22,771	20,755	13,860	23,467	25,032	263,964
190								
191	400W HPS AREA LIGHTING	108						
192	Customer bills		1,030	1,028	1,026	1,023	1,023	12,362
193	Demand		-	-	-	-	-	-
194	Usage		175,171	173,247	161,301	176,691	177,913	2,051,766
195	Usage per Customer		170	169	157	173	174	1,992
196	PB Base Rate Revenue		22,400	20,135	13,675	24,669	25,527	261,425
197	PB Fuel Rider Revenue		5,281	4,529	4,219	5,869	5,616	64,674
198	PB Other Rider Revenue		1,183	950	708	874	1,380	8,650
199	Total PB Retail Sales Revenue		28,864	25,614	18,602	31,412	32,522	334,749
200								
201	1000W HPS OUTDOOR LIGHTING	111						
202	Customer bills		631	625	623	645	645	7,377
203	Demand		-	-	-	-	-	-
204	Usage		244,786	246,864	217,739	233,129	236,153	2,802,455
205	Usage per Customer		388	395	350	361	366	4,561
206	PB Base Rate Revenue		16,917	15,635	10,140	17,692	17,574	192,338
207	PB Fuel Rider Revenue		7,382	6,523	5,868	7,861	7,127	88,382
208	PB Other Rider Revenue		669	544	410	457	669	4,021
209	Total PB Retail Sales Revenue		24,968	22,702	16,419	26,010	25,370	284,741
210								
211	1000W HPS AREA LIGHTING	112						
212	Customer bills		648	649	655	647	647	7,833
213	Demand		-	-	-	-	-	-
214	Usage		259,086	255,920	250,312	268,256	268,352	3,074,166
215	Usage per Customer		400	394	382	415	415	4,710
216	PB Base Rate Revenue		20,081	18,063	13,390	22,519	22,186	235,836
217	PB Fuel Rider Revenue		7,897	6,749	6,825	9,082	8,103	97,193
218	PB Other Rider Revenue		700	522	402	499	659	5,651
219	Total PB Retail Sales Revenue		28,679	25,334	20,617	32,100	30,949	338,679
220								
221	70W HPS AREA LIGHTING	115						
222	Customer bills		1	1	1	1	1	12
223	Demand		-	-	-	-	-	-
224	Usage		36	36	34	36	36	423
225	Usage per Customer		36	36	34	36	36	423
226	PB Base Rate Revenue		12	11	7	13	13	141
227	PB Fuel Rider Revenue		1	1	1	1	1	13
228	PB Other Rider Revenue		-	-	-	-	-	-
229	Total PB Retail Sales Revenue		13	12	8	14	15	154
230								
231	400W MH AREA LIGHTING	132						
232	Customer bills		816	808	809	812	812	9,777
233	Demand		-	-	-	-	-	-
234	Usage		130,811	129,335	129,158	137,482	137,393	1,548,755
235	Usage per Customer		160	160	160	169	169	1,901
236	PB Base Rate Revenue		16,086	14,702	10,531	18,757	18,871	191,635
237	PB Fuel Rider Revenue		3,896	3,408	3,404	4,584	4,230	48,630
238	PB Other Rider Revenue		540	449	347	403	574	3,580
239	Total PB Retail Sales Revenue		20,522	18,559	14,282	23,744	23,675	243,846
240								

SOUTHWESTERN ELECTRIC POWER COMPANY
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Line No.	Rate Schedule		Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18
241	400W MH OUTDOOR LIGHTING	133							
242	Customer bills		577	683	680	678	679	680	688
243	Demand		-	-	-	-	-	-	-
244	Usage		89,140	105,073	105,694	105,510	105,635	105,381	106,262
245	Usage per Customer		154	154	155	156	156	155	154
246	PB Base Rate Revenue		11,332	13,030	13,358	13,122	13,122	13,099	13,186
247	PB Fuel Rider Revenue		3,414	3,280	3,197	3,327	4,110	3,059	3,370
248	PB Other Rider Revenue		219	218	224	219	220	221	214
249	Total PB Retail Sales Revenue		14,965	16,528	16,779	16,668	17,452	16,379	16,770
250									
251	1000W MH AREA LIGHTING	135							
252	Customer bills		701	698	706	698	694	666	684
253	Demand		-	-	-	-	-	-	-
254	Usage		261,332	259,556	260,666	257,424	257,267	242,772	254,239
255	Usage per Customer		373	372	369	369	371	365	372
256	PB Base Rate Revenue		19,844	19,724	19,811	19,533	19,534	18,480	19,312
257	PB Fuel Rider Revenue		9,965	8,106	7,884	8,119	10,015	7,048	8,063
258	PB Other Rider Revenue		500	501	509	500	499	497	500
259	Total PB Retail Sales Revenue		30,310	28,331	28,204	28,152	30,048	26,025	27,876
260									
261	1000W MH OUTDOOR LIGHTING	136							
262	Customer bills		823	820	811	811	806	816	826
263	Demand		-	-	-	-	-	-	-
264	Usage		304,852	302,397	289,726	300,839	300,120	303,220	304,535
265	Usage per Customer		370	369	357	371	372	372	369
266	PB Base Rate Revenue		21,140	21,083	20,344	20,998	20,907	21,148	21,284
267	PB Fuel Rider Revenue		11,625	9,444	8,764	9,487	11,683	8,802	9,658
268	PB Other Rider Revenue		98	90	89	87	86	86	88
269	Total PB Retail Sales Revenue		32,863	30,617	29,196	30,571	32,676	30,036	31,030
270									
271	175W MV AREA LIGHTING	137							
272	Customer bills		380	382	386	376	382	377	370
273	Demand		-	-	-	-	-	-	-
274	Usage		25,820	25,892	25,411	25,568	25,549	25,572	24,099
275	Usage per Customer		68	68	66	68	67	68	65
276	PB Base Rate Revenue		7,145	7,161	7,061	7,068	7,083	7,084	6,834
277	PB Fuel Rider Revenue		984	809	768	806	994	742	764
278	PB Other Rider Revenue		248	249	245	267	247	250	227
279	Total PB Retail Sales Revenue		8,378	8,219	8,075	8,141	8,325	8,076	7,825
280									
281	250W MV AREA LIGHTING	138							
282	Customer bills		26	25	25	25	25	25	25
283	Demand		-	-	-	-	-	-	-
284	Usage		2,548	2,500	2,450	2,450	2,450	2,450	2,450
285	Usage per Customer		98	100	98	98	98	98	98
286	PB Base Rate Revenue		377	370	363	363	363	363	362
287	PB Fuel Rider Revenue		97	78	74	77	95	71	78
288	PB Other Rider Revenue		-	-	-	-	-	-	-
289	Total PB Retail Sales Revenue		474	448	437	440	458	434	439
290									
291	1000W MV AREA LIGHTING	140							
292	Customer bills		22	22	22	22	22	22	22
293	Demand		-	-	-	-	-	-	-
294	Usage		8,008	8,008	8,008	8,008	8,008	8,008	8,008
295	Usage per Customer		364	364	364	364	364	364	364
296	PB Base Rate Revenue		494	495	495	495	495	495	494
297	PB Fuel Rider Revenue		306	250	242	253	312	232	254
298	PB Other Rider Revenue		-	-	-	-	-	-	-
299	Total PB Retail Sales Revenue		801	745	738	748	808	728	748
300									

Line No.	Rate Schedule		Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	12 Month Total
241	400W MH OUTDOOR LIGHTING	133						
242	Customer bills		698	691	687	695	695	8,131
243	Demand		-	-	-	-	-	-
244	Usage		110,357	109,092	100,727	107,703	108,340	1,258,914
245	Usage per Customer		158	158	147	155	156	1,858
246	PB Base Rate Revenue		13,248	12,122	7,906	14,227	14,603	152,354
247	PB Fuel Rider Revenue		3,283	2,870	2,633	3,577	3,368	39,489
248	PB Other Rider Revenue		815	656	493	569	834	4,903
249	Total PB Retail Sales Revenue		17,347	15,647	11,031	18,373	18,805	196,745
250								
251	1000W MH AREA LIGHTING	135						
252	Customer bills		690	682	686	666	666	8,237
253	Demand		-	-	-	-	-	-
254	Usage		263,992	258,990	257,231	274,521	268,817	3,116,807
255	Usage per Customer		383	380	375	412	404	4,543
256	PB Base Rate Revenue		19,639	17,647	12,968	22,473	21,540	230,505
257	PB Fuel Rider Revenue		7,968	6,835	6,924	9,247	8,145	98,319
258	PB Other Rider Revenue		1,623	1,318	993	1,165	1,707	10,314
259	Total PB Retail Sales Revenue		29,230	25,801	20,884	32,886	31,393	339,138
260								
261	1000W MH OUTDOOR LIGHTING	136						
262	Customer bills		824	824	832	866	866	9,925
263	Demand		-	-	-	-	-	-
264	Usage		316,956	310,749	287,830	308,870	311,671	3,641,764
265	Usage per Customer		385	377	346	357	360	4,404
266	PB Base Rate Revenue		21,683	19,567	13,112	22,986	22,656	246,908
267	PB Fuel Rider Revenue		9,566	8,217	7,778	10,426	9,370	114,819
268	PB Other Rider Revenue		320	259	220	254	368	2,045
269	Total PB Retail Sales Revenue		31,569	28,044	21,110	33,666	32,394	363,772
270								
271	175W MV AREA LIGHTING	137						
272	Customer bills		359	344	335	335	335	4,361
273	Demand		-	-	-	-	-	-
274	Usage		25,383	24,002	25,140	26,578	27,027	306,041
275	Usage per Customer		71	70	75	79	81	845
276	PB Base Rate Revenue		7,043	6,216	4,596	7,855	8,379	83,524
277	PB Fuel Rider Revenue		771	621	640	871	889	9,660
278	PB Other Rider Revenue		608	485	417	493	703	4,439
279	Total PB Retail Sales Revenue		8,422	7,322	5,653	9,218	9,971	97,623
280								
281	250W MV AREA LIGHTING	138						
282	Customer bills		25	25	25	25	25	301
283	Demand		-	-	-	-	-	-
284	Usage		2,527	2,521	2,462	2,622	2,636	30,064
285	Usage per Customer		101	101	98	105	105	1,199
286	PB Base Rate Revenue		358	333	228	414	420	4,314
287	PB Fuel Rider Revenue		75	67	65	87	81	944
288	PB Other Rider Revenue		-	-	-	-	-	-
289	Total PB Retail Sales Revenue		432	400	293	502	501	5,258
290								
291	1000W MV AREA LIGHTING	140						
292	Customer bills		22	22	29	8	8	243
293	Demand		-	-	-	-	-	-
294	Usage		8,227	7,950	7,974	8,290	8,146	96,643
295	Usage per Customer		374	361	275	1,036	1,018	5,613
296	PB Base Rate Revenue		526	448	379	570	491	5,878
297	PB Fuel Rider Revenue		264	211	236	292	230	3,084
298	PB Other Rider Revenue		-	-	-	-	-	-
299	Total PB Retail Sales Revenue		790	659	615	862	721	8,962
300								

SOUTHWESTERN ELECTRIC POWER COMPANY
ARKANSAS JURISDICTIONAL
BILLING DETERMINANTS AND REVENUES
TEST YEAR ENDING DECEMBER 31, 2018

Line No.	Rate Schedule		Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18
301	GEN SVC-YR 2 W/C2 RIDER-1 MTR CHG	200							
302	Customer bills		283	283	283	282	284	284	282
303	Demand		3,523	3,485	3,407	3,284	4,307	3,239	3,358
304	Usage		1,252,854	1,127,310	774,739	620,180	568,851	858,761	962,789
305	Usage per Customer		4,427	3,983	2,738	2,199	2,003	3,024	3,414
306	PB Base Rate Revenue		48,313	46,768	36,362	31,422	37,782	42,118	45,919
307	PB Fuel Rider Revenue		47,727	35,199	23,429	19,550	22,130	24,928	30,528
308	PB Other Rider Revenue		17,272	13,995	10,824	9,337	9,344	12,588	13,077
309	Total PB Retail Sales Revenue		113,313	95,962	70,615	60,309	69,256	79,634	89,524
310									
311	UNMETERED GENERAL SERVICE	202							
312	Customer bills		8	8	8	8	8	8	8
313	Demand		-	-	-	-	-	-	-
314	Usage		2,302	2,302	2,302	2,302	2,302	2,302	2,302
315	Usage per Customer		288	288	288	288	288	288	288
316	PB Base Rate Revenue		127	127	126	127	140	140	140
317	PB Fuel Rider Revenue		88	72	70	73	90	67	73
318	PB Other Rider Revenue		34	34	35	35	36	36	33
319	Total PB Retail Sales Revenue		249	233	231	234	265	242	246
320									
321	RECREATIONAL LIGHTING	204							
322	Customer bills		106	106	102	105	101	105	103
323	Demand		1,998	2,811	5,447	6,585	6,268	5,150	4,130
324	Usage		338,217	318,951	331,775	354,940	329,786	283,201	237,932
325	Usage per Customer		3,191	3,009	3,253	3,380	3,265	2,697	2,310
326	PB Base Rate Revenue		9,646	9,170	9,320	9,903	9,336	8,145	6,946
327	PB Fuel Rider Revenue		12,883	9,959	10,033	11,193	12,829	8,221	7,544
328	PB Other Rider Revenue		4,113	3,876	4,184	4,480	4,083	3,523	2,864
329	Total PB Retail Sales Revenue		26,643	23,005	23,537	25,576	26,248	19,889	17,355
330									
331	GENERAL SERVICE - YEAR 2	220							
332	Customer bills		14,416	14,422	14,416	14,406	14,440	14,455	14,451
333	Demand		57,215	56,849	56,587	57,748	68,550	79,173	82,983
334	Usage		26,468,925	23,939,691	21,498,602	21,518,137	22,682,165	32,695,364	35,564,002
335	Usage per Customer		1,836	1,660	1,491	1,494	1,571	2,262	2,461
336	PB Base Rate Revenue		1,027,412	964,580	895,394	905,192	1,099,979	1,455,983	1,563,734
337	PB Fuel Rider Revenue		1,008,499	747,539	650,191	678,370	882,513	949,076	1,127,713
338	PB Other Rider Revenue		358,351	325,694	301,647	298,622	330,367	460,012	465,428
339	Total PB Retail Sales Revenue		2,394,262	2,037,813	1,847,232	1,882,184	2,312,859	2,865,071	3,156,875
340									
341	GENERAL SERVICE-YEAR 2 W/C2 RIDER	222							
342	Customer bills		1,233	1,240	1,237	1,245	1,242	1,233	1,235
343	Demand		11,053	11,118	10,271	9,926	12,117	9,771	10,095
344	Usage		5,326,157	4,690,378	3,566,366	3,137,584	2,868,740	3,835,144	4,134,011
345	Usage per Customer		4,320	3,783	2,883	2,520	2,310	3,110	3,347
346	PB Base Rate Revenue		191,471	177,157	143,290	131,514	149,149	168,828	179,590
347	PB Fuel Rider Revenue		202,908	146,439	107,852	98,893	111,610	111,326	131,084
348	PB Other Rider Revenue		69,382	60,754	48,783	43,091	42,611	53,651	54,203
349	Total PB Retail Sales Revenue		463,762	384,351	299,925	273,498	303,371	333,805	364,877
350									
351	LTG & POWER-TIME OF USE-SECONDARY	223							
352	Customer bills		2	2	2	2	2	2	2
353	Demand		2,682	2,829	3,488	2,736	3,045	3,017	2,703
354	Usage		488,948	493,409	525,164	564,024	628,550	486,045	520,967
355	Usage per Customer		244,474	246,705	262,582	282,012	314,275	243,023	260,484
356	PB Base Rate Revenue		7,775	17,786	14,160	7,865	16,257	17,162	25,682
357	PB Fuel Rider Revenue		18,754	15,404	15,916	17,798	24,486	14,163	16,534
358	PB Other Rider Revenue		6,461	6,537	6,325	7,124	6,146	6,029	7,958
359	Total PB Retail Sales Revenue		32,990	39,726	36,401	32,788	46,890	37,354	50,174
360									
361	LTG & POWER-TIME OF USE-PRIMARY	225							
362	Customer bills		1	1	1	1	1	1	1
363	Demand		2,309	2,737	2,736	2,423	2,829	2,444	2,480
364	Usage		1,385,867	1,361,404	1,482,996	1,425,781	1,564,997	1,503,032	1,269,579
365	Usage per Customer		1,385,867	1,361,404	1,482,996	1,425,781	1,564,997	1,503,032	1,269,579
366	PB Base Rate Revenue		15,508	16,506	16,950	16,067	18,134	16,698	15,789
367	PB Fuel Rider Revenue		51,128	41,169	43,434	43,526	58,963	42,254	38,986
368	PB Other Rider Revenue		14,888	14,719	16,352	15,347	16,827	16,083	13,425
369	Total PB Retail Sales Revenue		81,524	72,394	76,736	74,940	93,924	75,035	68,200

Line No.	Rate Schedule		Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	12 Month Total
301	GEN SVC-YR 2 W/C2 RIDER-1 MTR CHG	200						
302	Customer bills		282	284	287	283	287	3,403
303	Demand		3,301	3,314	3,164	3,285	3,285	40,949
304	Usage		983,282	912,319	696,333	577,641	710,735	10,045,793
305	Usage per Customer		3,483	3,218	2,429	2,040	2,480	35,438
306	PB Base Rate Revenue		44,845	40,066	20,062	33,026	37,032	463,715
307	PB Fuel Rider Revenue		29,038	24,123	18,334	19,261	21,680	315,928
308	PB Other Rider Revenue		49,365	37,913	24,387	22,847	39,803	260,752
309	Total PB Retail Sales Revenue		123,248	102,102	62,783	75,134	98,515	1,040,396
310								
311	UNMETERED GENERAL SERVICE	202						
312	Customer bills		8	8	8	8	8	96
313	Demand		-	-	-	-	-	-
314	Usage		2,374	2,369	2,224	2,369	2,381	27,830
315	Usage per Customer		297	297	276	296	296	3,477
316	PB Base Rate Revenue		138	129	77	140	142	1,551
317	PB Fuel Rider Revenue		70	63	58	79	73	874
318	PB Other Rider Revenue		128	104	82	94	138	788
319	Total PB Retail Sales Revenue		335	295	217	313	352	3,212
320								
321	RECREATIONAL LIGHTING	204						
322	Customer bills		101	102	104	104	106	1,244
323	Demand		4,024	4,958	5,771	5,310	5,310	57,760
324	Usage		229,955	263,937	280,045	292,984	245,892	3,507,615
325	Usage per Customer		2,282	2,592	2,702	2,816	2,329	33,827
326	PB Base Rate Revenue		6,462	6,898	5,081	9,042	7,850	97,800
327	PB Fuel Rider Revenue		6,784	6,978	7,358	9,757	7,512	111,052
328	PB Other Rider Revenue		10,429	9,645	8,399	9,616	11,518	76,731
329	Total PB Retail Sales Revenue		23,675	23,522	20,839	28,416	26,880	285,583
330								
331	GENERAL SERVICE - YEAR 2	220						
332	Customer bills		14,414	14,424	14,438	14,413	14,458	173,152
333	Demand		83,326	79,890	77,982	62,346	62,346	824,994
334	Usage		35,383,550	33,766,088	26,979,276	22,470,268	23,380,580	326,346,648
335	Usage per Customer		2,455	2,341	1,869	1,559	1,617	22,615
336	PB Base Rate Revenue		1,506,599	1,355,059	701,268	1,051,347	1,029,365	13,555,912
337	PB Fuel Rider Revenue		1,047,902	892,908	713,245	750,563	711,441	10,159,960
338	PB Other Rider Revenue		1,714,347	1,330,386	887,484	819,091	1,214,817	8,506,245
339	Total PB Retail Sales Revenue		4,268,847	3,578,353	2,301,996	2,621,002	2,955,623	32,222,117
340								
341	GENERAL SERVICE-YEAR 2 W/C2 RIDER	222						
342	Customer bills		1,234	1,244	1,228	1,227	1,239	14,836
343	Demand		9,928	9,998	9,275	9,603	9,603	122,759
344	Usage		4,092,173	3,961,390	3,142,550	2,876,426	3,385,381	45,016,300
345	Usage per Customer		3,316	3,185	2,559	2,345	2,733	36,411
346	PB Base Rate Revenue		171,407	157,724	79,545	132,929	147,801	1,830,406
347	PB Fuel Rider Revenue		120,989	104,747	82,830	95,957	103,173	1,417,809
348	PB Other Rider Revenue		200,967	157,855	104,380	104,993	176,634	1,117,305
349	Total PB Retail Sales Revenue		493,363	420,327	266,755	333,879	427,608	4,365,520
350								
351	LTG & POWER-TIME OF USE-SECONDARY	223						
352	Customer bills		2	2	2	2	2	24
353	Demand		2,712	3,089	4,777	832	832	32,742
354	Usage		523,550	507,805	580,982	458,964	502,771	6,281,179
355	Usage per Customer		260,457	253,050	291,466	228,712	251,807	3,139,046
356	PB Base Rate Revenue		76,270	27,909	58,246	(32,923)	12,876	249,065
357	PB Fuel Rider Revenue		17,628	13,505	17,734	17,312	13,506	202,743
358	PB Other Rider Revenue		10,264	5,616	3,473	4,228	4,297	74,460
359	Total PB Retail Sales Revenue		104,162	47,030	79,454	(11,383)	30,680	526,267
360								
361	LTG & POWER-TIME OF USE-PRIMARY	225						
362	Customer bills		1	1	1	1	1	12
363	Demand		2,740	-	5,966	2,814	2,814	32,292
364	Usage		1,339,328	1,131,825	1,454,479	1,399,554	1,433,501	16,752,344
365	Usage per Customer		1,342,623	1,133,786	1,445,708	1,399,007	1,425,749	16,740,530
366	PB Base Rate Revenue		16,335	9,478	10,064	17,229	17,396	186,153
367	PB Fuel Rider Revenue		38,265	28,813	37,012	45,141	42,412	511,103
368	PB Other Rider Revenue		53,257	50,397	37,529	39,175	58,377	346,377
369	Total PB Retail Sales Revenue		107,857	88,687	84,605	101,544	118,185	1,043,633

SOUTHWESTERN ELECTRIC POWER COMPANY
ARKANSAS JURISDICTIONAL
BILLING DETERMINANTS AND REVENUES
TEST YEAR ENDING DECEMBER 31, 2018

Line No.	Rate Schedule		Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18
370									
371	LTG & POWER-YEAR 2-SECONDARY	240							
372	Customer bills		1,272	1,272	1,269	1,262	1,266	1,263	1,263
373	Demand		196,194	195,230	193,790	193,849	202,745	216,633	214,795
374	Usage		68,692,156	64,410,964	63,670,312	63,754,696	66,608,044	82,346,425	83,643,439
375	Usage per Customer		54,003	50,638	50,174	50,519	52,613	65,199	66,226
376	PB Base Rate Revenue		1,528,194	1,505,922	1,501,023	1,481,901	2,599,151	2,959,688	2,993,085
377	PB Fuel Rider Revenue		2,623,582	2,012,079	1,926,148	2,012,062	2,595,822	2,390,621	2,651,935
378	PB Other Rider Revenue		700,302	663,506	653,690	673,237	799,966	962,583	924,456
379	Total PB Retail Sales Revenue		4,852,078	4,181,507	4,080,861	4,167,200	5,994,939	6,312,891	6,569,476
380									
381	LTG & PWR-YR 2-SECONDARY W/C2 RIDER	243							
382	Customer bills		332	333	334	339	333	333	333
383	Demand		46,373	46,844	43,346	44,978	46,237	48,803	50,867
384	Usage		20,033,206	17,702,382	16,255,033	15,771,371	15,720,311	19,830,345	20,272,785
385	Usage per Customer		60,341	53,160	48,668	46,523	47,208	59,551	60,879
386	PB Base Rate Revenue		381,759	374,005	344,436	351,346	601,084	685,840	710,157
387	PB Fuel Rider Revenue		763,993	552,846	491,681	497,422	612,125	575,664	643,017
388	PB Other Rider Revenue		193,543	175,979	161,649	157,126	179,815	222,222	215,747
389	Total PB Retail Sales Revenue		1,339,294	1,102,830	997,766	1,005,894	1,393,024	1,483,726	1,568,922
390									
391	LTG & POWER-YEAR 2-PRIMARY	246							
392	Customer bills		35	33	33	34	34	37	35
393	Demand		59,514	57,716	62,702	66,056	69,551	73,211	74,710
394	Usage		27,745,620	28,783,260	28,109,400	31,799,580	33,506,940	36,900,720	35,937,660
395	Usage per Customer		792,732	872,220	851,800	935,282	985,498	997,317	1,026,790
396	PB Base Rate Revenue		441,552	447,725	452,178	496,035	995,755	1,078,379	1,074,685
397	PB Fuel Rider Revenue		1,028,707	870,971	824,211	972,984	1,267,062	1,037,660	1,105,181
398	PB Other Rider Revenue		235,601	245,132	232,854	259,880	323,673	345,095	324,957
399	Total PB Retail Sales Revenue		1,705,860	1,563,829	1,509,244	1,728,899	2,586,489	2,461,134	2,504,823
400									
401	LTG & PWR-YR 2-PRIMARY W/C2 RIDER	249							
402	Customer bills		10	10	10	10	10	10	10
403	Demand		21,610	21,505	21,348	18,763	26,316	23,399	23,461
404	Usage		10,018,800	10,063,200	9,027,600	9,803,996	10,088,404	11,398,800	11,281,200
405	Usage per Customer		1,001,880	1,006,320	902,760	980,400	1,008,840	1,139,880	1,128,120
406	PB Base Rate Revenue		160,944	161,324	156,816	160,902	316,356	338,394	337,271
407	PB Fuel Rider Revenue		371,824	304,623	264,687	299,827	382,058	320,554	347,028
408	PB Other Rider Revenue		61,595	61,418	54,751	59,712	75,820	81,598	75,171
409	Total PB Retail Sales Revenue		594,364	527,366	476,254	520,441	774,234	740,547	759,470
410									
411	LTG & PWR-YR 2-PRI W/SEC FUEL & C2	250							
412	Customer bills		2	2	2	2	2	2	2
413	Demand		913	796	702	706	781	861	959
414	Usage		417,491	328,691	239,091	242,291	263,891	376,691	457,491
415	Usage per Customer		208,746	164,346	119,546	121,146	131,946	188,346	228,746
416	PB Base Rate Revenue		6,827	5,794	4,803	4,902	9,529	11,880	13,855
417	PB Fuel Rider Revenue		15,903	10,263	7,230	7,637	10,266	10,934	14,506
418	PB Other Rider Revenue		4,702	3,737	2,850	2,827	3,469	4,779	5,481
419	Total PB Retail Sales Revenue		27,432	19,794	14,884	15,366	23,264	27,594	33,842
420									
421	LTG & PWR-YEAR 2-PRIMARY@SUBSTATION	251							
422	Customer bills		1	1	1	1	1	1	1
423	Demand		6,986	6,355	6,355	6,170	6,007	6,021	6,209
424	Usage		2,332,800	2,044,800	1,886,400	1,872,000	1,886,400	1,857,600	1,929,600
425	Usage per Customer		2,332,800	2,044,800	1,886,400	1,872,000	1,886,400	1,857,600	1,929,600
426	PB Base Rate Revenue		47,684	42,987	42,818	41,448	70,312	70,180	72,638
427	PB Fuel Rider Revenue		85,836	61,333	54,804	56,784	70,750	51,758	58,819
428	PB Other Rider Revenue		12,598	11,356	10,201	10,368	13,268	12,908	12,020
429	Total PB Retail Sales Revenue		146,117	115,675	107,824	108,600	154,330	134,847	143,476
430									
431	GS SECONDARY NET-METERING	282							
432	Customer bills		10	10	12	11	13	13	13
433	Demand		88	94	104	75	137	215	224
434	Usage		25,698	29,518	28,503	25,798	24,898	36,314	48,872
435	Usage per Customer		2,570	2,952	2,375	2,345	1,915	2,793	3,759
436	PB Base Rate Revenue		1,080	1,145	1,232	1,053	1,443	2,061	2,489
437	PB Fuel Rider Revenue		979	922	862	813	969	1,054	1,550
438	PB Other Rider Revenue		361	463	403	366	396	528	641
439	Total PB Retail Sales Revenue		2,419	2,530	2,497	2,232	2,808	3,643	4,680
440									

Line No.	Rate Schedule		Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	12 Month Total
370								
371	LTG & POWER-YEAR 2-SECONDARY	240						
372	Customer bills		1,272	1,271	1,284	1,308	1,281	15,283
373	Demand		224,851	222,063	218,958	207,254	207,254	2,493,616
374	Usage		85,146,567	83,678,066	78,126,081	70,066,887	70,997,200	881,140,836
375	Usage per Customer		66,925	65,849	60,843	53,566	55,438	691,993
376	PB Base Rate Revenue		3,081,075	2,754,200	1,216,172	1,802,206	1,612,055	25,034,671
377	PB Fuel Rider Revenue		2,638,159	2,217,413	2,209,791	2,417,063	2,067,562	27,762,237
378	PB Other Rider Revenue		2,768,372	2,196,684	1,449,257	1,447,574	2,062,270	15,301,896
379	Total PB Retail Sales Revenue		8,487,606	7,168,296	4,875,221	5,666,842	5,741,888	68,098,805
380								
381	LTG & PWR-YR 2-SECONDARY W/C2 RIDER	243						
382	Customer bills		333	330	334	340	330	4,004
383	Demand		50,379	49,697	48,232	46,115	46,115	567,984
384	Usage		20,501,683	19,879,355	17,424,449	16,258,018	17,151,286	216,800,223
385	Usage per Customer		61,501	60,324	52,201	47,789	52,034	650,179
386	PB Base Rate Revenue		704,795	632,941	247,762	398,096	382,696	5,814,916
387	PB Fuel Rider Revenue		620,713	526,235	476,962	551,882	511,610	6,824,149
388	PB Other Rider Revenue		738,523	578,782	366,601	378,315	579,841	3,948,144
389	Total PB Retail Sales Revenue		2,064,031	1,737,958	1,091,325	1,328,293	1,474,146	16,587,209
390								
391	LTG & POWER-YEAR 2-PRIMARY	246						
392	Customer bills		33	33	33	33	34	407
393	Demand		71,384	73,345	73,549	66,714	66,714	815,165
394	Usage		36,019,429	36,807,740	32,165,780	30,803,423	31,341,439	389,920,990
395	Usage per Customer		1,089,211	1,113,872	974,089	931,477	920,653	11,490,941
396	PB Base Rate Revenue		1,133,093	994,327	397,490	546,253	449,728	8,507,201
397	PB Fuel Rider Revenue		1,139,858	947,079	939,602	1,061,506	842,534	12,037,354
398	PB Other Rider Revenue		551,254	453,481	304,538	340,040	441,242	4,057,749
399	Total PB Retail Sales Revenue		2,824,205	2,394,887	1,641,630	1,947,799	1,733,504	24,602,304
400								
401	LTG & PWR-YR 2-PRIMARY W/C2 RIDER	249						
402	Customer bills		10	10	10	10	10	120
403	Demand		23,423	23,126	22,665	20,844	20,844	267,305
404	Usage		11,417,971	11,250,530	10,592,100	10,478,544	10,907,271	126,328,415
405	Usage per Customer		1,138,603	1,122,989	1,060,761	1,044,958	1,091,003	12,626,514
406	PB Base Rate Revenue		365,108	304,279	144,839	192,021	154,605	2,792,862
407	PB Fuel Rider Revenue		368,496	289,817	318,675	366,536	286,960	3,921,086
408	PB Other Rider Revenue		107,820	75,832	50,025	60,406	77,829	841,977
409	Total PB Retail Sales Revenue		841,424	669,928	513,539	618,963	519,394	7,555,925
410								
411	LTG & PWR-YR 2-PRI W/SEC FUEL & C2	250						
412	Customer bills		2	2	2	2	2	24
413	Demand		962	864	875	718	718	9,854
414	Usage		391,764	384,335	308,266	234,479	298,612	3,943,092
415	Usage per Customer		196,364	192,500	153,204	117,194	148,498	1,970,578
416	PB Base Rate Revenue		12,431	10,973	3,930	5,275	5,734	95,933
417	PB Fuel Rider Revenue		11,557	10,162	8,100	7,809	9,122	123,490
418	PB Other Rider Revenue		17,940	14,197	8,685	7,186	12,961	88,816
419	Total PB Retail Sales Revenue		41,929	35,331	20,716	20,270	27,818	308,238
420								
421	LTG & PWR-YEAR 2-PRIMARY@SUBSTATION	251						
422	Customer bills		1	1	1	1	1	12
423	Demand		6,071	6,012	6,154	6,017	6,017	74,374
424	Usage		1,948,692	1,791,490	2,260,391	2,228,948	2,408,069	24,447,191
425	Usage per Customer		1,938,883	1,785,478	2,267,976	2,221,468	2,412,110	24,435,516
426	PB Base Rate Revenue		78,483	62,686	39,990	58,146	46,768	674,140
427	PB Fuel Rider Revenue		62,896	45,746	68,065	77,677	62,133	756,601
428	PB Other Rider Revenue		12,736	7,869	7,247	9,400	10,518	130,487
429	Total PB Retail Sales Revenue		154,115	116,300	115,302	145,223	119,419	1,561,228
430								
431	GS SECONDARY NET-METERING	282						
432	Customer bills		13	13	9	9	9	135
433	Demand		219	214	192	122	122	1,806
434	Usage		61,732	54,320	33,823	27,362	25,586	422,424
435	Usage per Customer		4,760	4,186	3,735	3,039	2,828	37,258
436	PB Base Rate Revenue		2,833	2,415	989	1,361	1,220	19,320
437	PB Fuel Rider Revenue		1,821	1,436	889	911	782	12,987
438	PB Other Rider Revenue		3,118	2,256	1,190	1,044	1,496	12,262
439	Total PB Retail Sales Revenue		7,772	6,107	3,068	3,316	3,497	44,569
440								

SOUTHWESTERN ELECTRIC POWER COMPANY
ARKANSAS JURISDICTIONAL
BILLING DETERMINANTS AND REVENUES
TEST YEAR ENDING DECEMBER 31, 2018

Line No.	Rate Schedule		Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18
441	LTG & PWR-SEC NET-METERING	292							
442	Customer bills		4	4	4	4	4	4	4
443	Demand		905	926	998	915	918	1,004	1,003
444	Usage		330,180	326,080	340,000	318,640	338,120	448,920	437,580
445	Usage per Customer		82,545	81,520	85,000	79,660	84,530	112,230	109,395
446	PB Base Rate Revenue		7,066	7,182	7,590	7,070	12,340	14,767	14,593
447	PB Fuel Rider Revenue		12,577	10,182	10,282	10,044	13,154	13,031	13,875
448	PB Other Rider Revenue		3,874	3,838	4,117	3,768	4,447	5,745	5,340
449	Total PB Retail Sales Revenue		23,517	21,202	21,988	20,881	29,941	33,543	33,808
450									
451	LLP PRIMARY W/ SBMAA	319							
452	Customer bills		1	1	1	1	1	1	1
453	Demand		13,309	13,309	13,309	13,309	15,048	15,624	15,909
454	Usage		5,788,145	5,306,113	7,285,090	7,534,208	7,278,753	7,147,765	7,603,434
455	Usage per Customer		5,788,145	5,306,113	7,285,090	7,534,208	7,278,753	7,147,765	7,603,434
456	PB Base Rate Revenue		109,993	107,898	115,887	117,917	229,156	230,971	240,173
457	PB Fuel Rider Revenue		213,537	160,458	213,365	230,005	274,234	200,942	233,487
458	PB Other Rider Revenue		33,135	31,265	39,621	39,765	53,805	53,611	51,045
459	Total PB Retail Sales Revenue		356,665	299,621	368,873	387,687	557,195	485,524	524,706
460									
461	PULP & PAPER MILL SERVICE-DOMTAR	326							
462	Customer bills		1	1	1	1	1	1	1
463	Demand		38,156	38,156	38,156	38,156	38,156	38,156	38,045
464	Usage		17,988,789	15,590,264	20,427,612	18,902,206	20,336,314	23,468,803	24,439,834
465	Usage per Customer		17,988,789	15,590,264	20,427,612	18,902,206	20,336,314	23,468,803	24,439,834
466	PB Base Rate Revenue		360,366	280,630	472,220	264,118	377,716	384,599	389,166
467	PB Fuel Rider Revenue		662,551	468,083	594,055	561,906	778,367	654,559	745,727
468	PB Other Rider Revenue		102,617	94,616	108,738	105,918	112,561	122,966	118,307
469	Total PB Retail Sales Revenue		1,125,533	843,329	1,175,012	931,942	1,268,644	1,162,124	1,253,200
470									
471	LTG&PWR-PRIMARY-CURTAILABLE DEMAND	336							
472	Customer bills		5	5	5	5	5	5	5
473	Demand		14,972	14,464	14,293	14,408	14,524	13,972	14,139
474	Usage		2,626,612	2,464,609	2,353,580	2,495,784	2,456,611	2,500,384	2,298,011
475	Usage per Customer		525,322	492,922	470,716	499,157	491,322	500,077	459,602
476	PB Base Rate Revenue		62,739	63,451	62,815	62,846	108,688	109,130	106,478
477	PB Fuel Rider Revenue		97,386	74,588	68,994	76,342	92,839	70,309	70,650
478	PB Other Rider Revenue		27,748	25,779	24,875	25,561	29,128	29,500	24,934
479	Total PB Retail Sales Revenue		187,874	163,818	156,683	164,749	230,656	208,940	202,063
480									
481	LARGE LTG & POWER-YR 2-TRANS 69 KV	342							
482	Customer bills		1	1	1	1	1	1	1
483	Demand		21,323	21,298	21,834	21,529	21,937	21,899	22,415
484	Usage		11,355,942	11,579,829	12,784,737	13,650,699	12,998,377	13,333,213	13,541,989
485	Usage per Customer		11,355,942	11,579,829	12,784,737	13,650,699	12,998,377	13,333,213	13,541,989
486	PB Base Rate Revenue		109,514	109,832	117,474	118,594	270,634	276,356	280,685
487	PB Fuel Rider Revenue		418,255	347,673	371,793	414,487	487,997	371,871	413,204
488	PB Other Rider Revenue		50,577	52,278	53,990	58,758	77,671	77,954	72,888
489	Total PB Retail Sales Revenue		578,346	509,784	543,257	591,839	836,302	726,181	766,777
490									
491	LARGE LTG & POWER-YEAR 2-PRIMARY	346							
492	Customer bills		1	1	1	1	1	1	1
493	Demand		11,719	11,324	11,454	11,782	13,012	13,234	13,669
494	Usage		7,096,390	7,463,147	7,099,875	7,716,833	7,810,243	8,577,665	8,479,329
495	Usage per Customer		7,096,390	7,463,147	7,099,875	7,716,833	7,810,243	8,577,665	8,479,329
496	PB Base Rate Revenue		94,211	93,471	94,317	97,805	210,468	224,954	226,590
497	PB Fuel Rider Revenue		263,547	225,941	208,192	236,261	295,658	241,226	260,880
498	PB Other Rider Revenue		35,096	36,816	33,761	37,354	53,149	56,412	51,293
499	Total PB Retail Sales Revenue		392,854	356,228	336,271	371,420	559,276	522,592	538,763
500									
501	MUNICIPAL STREET & PARKWAY LTG-YR 2	528							
502	Customer bills		4,832	4,832	4,832	4,832	4,829	4,827	4,824
503	Demand		-	-	-	-	-	-	-
504	Usage		377,533	377,544	377,544	377,544	377,795	377,420	377,335
505	Usage per Customer		78	78	78	78	78	78	78
506	PB Base Rate Revenue		50,977	50,979	50,980	50,981	50,975	50,953	50,851
507	PB Fuel Rider Revenue		14,370	11,782	11,417	11,893	14,674	10,960	11,962
508	PB Other Rider Revenue		1,201	1,201	1,201	1,201	1,201	1,201	1,155
509	Total PB Retail Sales Revenue		66,549	63,963	63,597	64,075	66,850	63,114	63,968
510									

Line No.	Rate Schedule		Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	12 Month Total
441	LTG & PWR-SEC NET-METERING	292						
442	Customer bills		4	4	4	4	4	48
443	Demand		982	912	894	860	860	11,178
444	Usage		437,974	437,936	316,351	251,856	342,809	4,326,446
445	Usage per Customer		109,763	109,674	78,611	62,939	85,239	1,081,106
446	PB Base Rate Revenue		13,996	12,686	3,721	6,736	8,039	115,787
447	PB Fuel Rider Revenue		12,920	11,579	8,312	8,388	10,472	134,815
448	PB Other Rider Revenue		20,100	16,200	8,772	7,964	15,372	99,537
449	Total PB Retail Sales Revenue		47,017	40,465	20,805	23,088	33,884	350,140
450								
451	LLP PRIMARY W/ SBMAA	319						
452	Customer bills		1	1	1	1	1	12
453	Demand		17,002	16,384	-	30,552	30,552	194,307
454	Usage		8,341,734	7,817,772	5,720,434	4,658,010	5,325,654	79,807,113
455	Usage per Customer		8,362,256	7,831,314	5,685,939	4,656,190	5,296,856	79,776,063
456	PB Base Rate Revenue		251,719	224,745	71,831	115,229	119,586	1,935,106
457	PB Fuel Rider Revenue		238,326	200,182	145,568	150,238	157,568	2,417,909
458	PB Other Rider Revenue		209,844	161,422	86,286	81,326	128,943	970,069
459	Total PB Retail Sales Revenue		699,889	586,349	303,685	346,794	406,097	5,323,084
460								
461	PULP & PAPER MILL SERVICE-DOMTAR	326						
462	Customer bills		1	1	1	1	1	12
463	Demand		48,045	38,020	38,020	38,020	38,020	467,108
464	Usage		24,541,135	23,471,239	20,142,896	17,577,509	17,275,757	244,162,358
465	Usage per Customer		24,417,606	23,392,476	20,210,489	17,518,524	17,304,743	243,997,661
466	PB Base Rate Revenue		393,909	318,201	246,051	438,047	339,896	4,264,919
467	PB Fuel Rider Revenue		792,877	599,937	607,146	613,164	446,186	7,524,558
468	PB Other Rider Revenue		125,426	82,554	66,121	76,580	80,378	1,196,781
469	Total PB Retail Sales Revenue		1,312,212	1,000,692	919,317	1,127,790	866,461	12,986,258
470								
471	LTG&PWR-PRIMARY-CURTAILABLE DEMAND	336						
472	Customer bills		5	5	5	5	5	60
473	Demand		14,762	14,065	13,751	13,700	13,700	170,750
474	Usage		2,404,384	2,304,221	2,442,846	2,191,576	2,200,773	28,739,391
475	Usage per Customer		480,612	460,702	487,447	437,623	439,017	5,744,519
476	PB Base Rate Revenue		112,597	97,543	43,979	68,044	66,561	964,871
477	PB Fuel Rider Revenue		74,924	59,276	70,775	75,231	59,573	890,888
478	PB Other Rider Revenue		49,356	34,815	26,595	28,781	34,936	362,010
479	Total PB Retail Sales Revenue		236,878	191,635	141,349	172,056	161,070	2,217,769
480								
481	LARGE LTG & POWER-YR 2-TRANS 69 KV	342						
482	Customer bills		1	1	1	1	1	12
483	Demand		22,655	22,970	22,294	21,542	21,542	263,237
484	Usage		14,338,050	13,587,093	13,909,658	14,250,222	11,199,694	156,529,504
485	Usage per Customer		14,265,878	13,541,499	13,956,335	14,202,403	11,218,485	156,429,387
486	PB Base Rate Revenue		315,347	257,654	103,416	139,965	102,527	2,201,998
487	PB Fuel Rider Revenue		463,235	347,293	419,264	497,097	289,258	4,841,426
488	PB Other Rider Revenue		80,807	51,231	35,596	46,118	40,263	698,133
489	Total PB Retail Sales Revenue		859,389	656,178	558,276	683,181	432,047	7,741,557
490								
491	LARGE LTG & POWER-YEAR 2-PRIMARY	346						
492	Customer bills		1	1	1	1	1	12
493	Demand		13,674	13,821	12,914	11,627	11,627	149,855
494	Usage		8,674,241	9,046,287	7,667,021	7,379,468	7,502,832	94,513,331
495	Usage per Customer		8,630,579	9,015,930	7,692,749	7,354,705	7,515,421	94,452,866
496	PB Base Rate Revenue		248,826	215,513	84,196	110,779	89,571	1,790,701
497	PB Fuel Rider Revenue		282,580	233,151	233,024	259,566	195,392	2,935,418
498	PB Other Rider Revenue		55,192	37,833	22,166	27,269	29,412	475,753
499	Total PB Retail Sales Revenue		586,597	486,497	339,386	397,614	314,375	5,201,872
500								
501	MUNICIPAL STREET & PARKWAY LTG-YR 2	528						
502	Customer bills		4,825	4,823	4,820	4,818	4,818	57,912
503	Demand		-	-	-	-	-	-
504	Usage		377,927	377,787	377,642	377,697	377,685	4,531,452
505	Usage per Customer		78	78	78	78	78	939
506	PB Base Rate Revenue		47,540	45,221	45,418	66,003	54,085	614,963
507	PB Fuel Rider Revenue		10,689	9,728	10,750	15,132	11,322	144,680
508	PB Other Rider Revenue		117,726	128,894	91,468	115,315	107,065	568,829
509	Total PB Retail Sales Revenue		175,955	183,844	147,636	196,450	172,472	1,328,471
510								

SOUTHWESTERN ELECTRIC POWER COMPANY
ARKANSAS JURISDICTIONAL
BILLING DETERMINANTS AND REVENUES
TEST YEAR ENDING DECEMBER 31, 2018

Line No.	Rate Schedule		Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18
511	MUNICIPAL STREET LIGHTING-YEAR 2	529							
512	Customer bills		4,961	4,939	4,928	4,912	4,901	4,887	4,867
513	Demand		-	-	-	-	-	-	-
514	Usage		312,460	311,007	309,386	308,313	307,444	306,646	305,741
515	Usage per Customer		63	63	63	63	63	63	63
516	PB Base Rate Revenue		28,430	28,305	28,141	28,038	27,949	27,874	27,934
517	PB Fuel Rider Revenue		11,894	9,706	9,356	9,712	11,942	8,905	9,692
518	PB Other Rider Revenue		6,278	6,275	6,273	6,269	6,271	6,269	6,025
519	Total PB Retail Sales Revenue		46,601	44,285	43,770	44,019	46,161	43,048	43,650
520									
521	MUNICIPAL STREET LTG-YR 2-VA HILLS	530							
522	Customer bills		39	39	39	39	39	39	39
523	Demand		-	-	-	-	-	-	-
524	Usage		1,638	1,638	1,638	1,638	1,638	1,638	1,638
525	Usage per Customer		42	42	42	42	42	42	42
526	PB Base Rate Revenue		320	320	320	320	320	320	319
527	PB Fuel Rider Revenue		62	51	50	52	64	48	52
528	PB Other Rider Revenue		-	-	-	-	-	-	-
529	Total PB Retail Sales Revenue		382	371	369	371	383	367	371
530									
531	MUNICIPAL STREET & PARKWAY LTG	531							
532	Customer bills		4,085	4,109	4,119	4,137	4,151	4,174	4,200
533	Demand		-	-	-	-	-	-	-
534	Usage		250,657	251,707	253,055	253,654	254,522	255,441	256,483
535	Usage per Customer		61	61	61	61	61	61	61
536	PB Base Rate Revenue		33,506	33,634	33,787	33,871	33,981	34,120	34,185
537	PB Fuel Rider Revenue		9,541	7,855	7,652	7,991	9,886	7,418	8,131
538	PB Other Rider Revenue		778	778	778	778	779	779	741
539	Total PB Retail Sales Revenue		43,825	42,267	42,217	42,640	44,645	42,317	43,057
540									
541	PUBLIC ST&HIWAY LTG-YR2-ENERGY ONLY	534							
542	Customer bills		123	123	123	123	123	123	123
543	Demand		-	-	-	-	-	-	-
544	Usage		6,970	6,970	6,970	6,970	6,970	6,970	6,970
545	Usage per Customer		57	57	57	57	57	57	57
546	PB Base Rate Revenue		495	495	495	495	495	495	494
547	PB Fuel Rider Revenue		265	218	211	220	271	202	221
548	PB Other Rider Revenue		8	8	8	8	8	8	8
549	Total PB Retail Sales Revenue		768	721	714	723	774	705	723
550									
551	PUBLIC ST & HIGHWAY LTG - YEAR 2	535							
552	Customer bills		54	54	54	54	54	54	54
553	Demand		-	-	-	-	-	-	-
554	Usage		4,493	4,493	4,493	4,493	4,493	4,493	4,493
555	Usage per Customer		83	83	83	83	83	83	83
556	PB Base Rate Revenue		422	422	422	422	422	422	421
557	PB Fuel Rider Revenue		171	140	136	142	175	130	142
558	PB Other Rider Revenue		-	-	-	-	-	-	-
559	Total PB Retail Sales Revenue		593	562	558	564	597	553	563
560									
561	PUBLIC ST & HIGHWAY LTG-ENERGY ONLY	536							
562	Customer bills		84	84	84	84	84	84	84
563	Demand		-	-	-	-	-	-	-
564	Usage		9,311	9,311	9,311	9,311	9,311	9,311	9,311
565	Usage per Customer		111	111	111	111	111	111	111
566	PB Base Rate Revenue		400	400	400	400	400	400	400
567	PB Fuel Rider Revenue		354	291	282	293	362	270	295
568	PB Other Rider Revenue		53	53	53	53	53	53	52
569	Total PB Retail Sales Revenue		807	744	735	746	815	723	747
570									
571	PUBLIC ST & HIGHWAY LTG	537							
572	Customer bills		42	42	42	42	42	42	42
573	Demand		-	-	-	-	-	-	-
574	Usage		2,514	2,514	2,514	2,499	2,495	2,495	2,495
575	Usage per Customer		60	60	60	60	59	59	59
576	PB Base Rate Revenue		128	128	128	128	127	127	129
577	PB Fuel Rider Revenue		96	78	76	79	97	72	79
578	PB Other Rider Revenue		52	52	52	52	52	52	50
579	Total PB Retail Sales Revenue		276	259	256	259	277	252	258

Line No.	Rate Schedule		Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	12 Month Total
511	MUNICIPAL STREET LIGHTING-YEAR 2	529						
512	Customer bills		4,844	4,820	4,811	4,791	4,791	58,452
513	Demand		-	-	-	-	-	-
514	Usage		304,411	303,050	316,468	314,812	313,393	3,713,131
515	Usage per Customer		63	63	66	66	65	762
516	PB Base Rate Revenue		26,086	24,524	25,948	37,515	30,552	341,297
517	PB Fuel Rider Revenue		8,610	7,804	9,008	12,612	9,395	118,635
518	PB Other Rider Revenue		613,858	672,161	478,713	603,155	559,798	2,971,344
519	Total PB Retail Sales Revenue		648,554	704,488	513,670	653,283	599,745	3,431,276
520								
521	MUNICIPAL STREET LTG-YR 2-VA HILLS	530						
522	Customer bills		39	39	39	39	39	468
523	Demand		-	-	-	-	-	-
524	Usage		1,641	1,641	1,637	1,638	1,638	19,660
525	Usage per Customer		42	42	42	42	42	504
526	PB Base Rate Revenue		300	283	285	414	339	3,856
527	PB Fuel Rider Revenue		46	42	47	66	49	628
528	PB Other Rider Revenue		-	-	-	-	-	-
529	Total PB Retail Sales Revenue		346	326	331	479	388	4,484
530								
531	MUNICIPAL STREET & PARKWAY LTG	531						
532	Customer bills		4,223	4,246	4,264	4,288	4,288	50,284
533	Demand		-	-	-	-	-	-
534	Usage		258,408	259,912	246,667	248,268	249,693	3,038,467
535	Usage per Customer		61	61	58	58	58	725
536	PB Base Rate Revenue		32,311	30,734	29,448	43,019	35,420	408,015
537	PB Fuel Rider Revenue		7,309	6,693	7,021	9,946	7,485	96,929
538	PB Other Rider Revenue		75,558	82,732	59,442	75,007	69,651	367,801
539	Total PB Retail Sales Revenue		115,178	120,158	95,911	127,972	112,556	872,745
540								
541	PUBLIC ST&HIWAY LTG-YR2-ENERGY ONLY	534						
542	Customer bills		123	123	123	123	123	1,476
543	Demand		-	-	-	-	-	-
544	Usage		6,982	6,982	6,965	6,968	6,970	83,657
545	Usage per Customer		57	57	57	57	57	680
546	PB Base Rate Revenue		464	440	439	638	523	5,970
547	PB Fuel Rider Revenue		197	180	198	279	209	2,671
548	PB Other Rider Revenue		778	852	593	748	694	3,719
549	Total PB Retail Sales Revenue		1,440	1,471	1,230	1,665	1,426	12,359
550								
551	PUBLIC ST & HIGHWAY LTG - YEAR 2	535						
552	Customer bills		54	54	54	54	54	648
553	Demand		-	-	-	-	-	-
554	Usage		4,501	4,501	4,490	4,492	4,493	53,927
555	Usage per Customer		83	83	83	83	83	999
556	PB Base Rate Revenue		396	374	375	545	446	5,090
557	PB Fuel Rider Revenue		127	116	128	180	135	1,722
558	PB Other Rider Revenue		-	-	-	-	-	-
559	Total PB Retail Sales Revenue		523	490	503	725	581	6,811
560								
561	PUBLIC ST & HIGHWAY LTG-ENERGY ONLY	536						
562	Customer bills		84	84	84	84	84	1,008
563	Demand		-	-	-	-	-	-
564	Usage		9,327	9,327	9,304	9,309	9,311	111,755
565	Usage per Customer		111	111	111	111	111	1,330
566	PB Base Rate Revenue		376	355	356	517	424	4,827
567	PB Fuel Rider Revenue		264	240	265	373	279	3,568
568	PB Other Rider Revenue		5,339	5,845	4,002	5,046	4,684	25,288
569	Total PB Retail Sales Revenue		5,978	6,441	4,623	5,936	5,387	33,683
570								
571	PUBLIC ST & HIGHWAY LTG	537						
572	Customer bills		42	42	42	42	42	504
573	Demand		-	-	-	-	-	-
574	Usage		2,499	2,499	2,525	2,513	2,514	30,077
575	Usage per Customer		60	60	60	60	60	716
576	PB Base Rate Revenue		121	115	116	169	138	1,554
577	PB Fuel Rider Revenue		71	64	72	101	75	960
578	PB Other Rider Revenue		5,114	5,600	4,004	5,039	4,678	24,799
579	Total PB Retail Sales Revenue		5,307	5,779	4,192	5,308	4,891	27,314

SOUTHWESTERN ELECTRIC POWER COMPANY
ARKANSAS JURISDICTIONAL
BILLING DETERMINANTS AND REVENUES
TEST YEAR ENDING DECEMBER 31, 2018

Line No.	Rate Schedule		Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18
580									
581	MUNI PUMPING-YR2-SECONDARY	540							
582	Customer bills		65	64	64	63	63	63	63
583	Demand		2,511	2,446	2,474	2,474	2,474	2,476	2,476
584	Usage		399,823	350,758	355,464	337,140	286,904	292,133	258,070
585	Usage per Customer		6,151	5,481	5,554	5,351	4,554	4,637	4,096
586	PB Base Rate Revenue		12,778	11,222	11,272	10,783	10,613	10,800	9,591
587	PB Fuel Rider Revenue		15,230	10,952	10,749	10,627	11,161	8,480	8,183
588	PB Other Rider Revenue		4,568	4,020	4,171	3,876	3,361	3,420	2,924
589	Total PB Retail Sales Revenue		32,576	26,194	26,192	25,287	25,135	22,700	20,697
590									
591	MUNI SERVICE-YEAR 2-SECONDARY	544							
592	Customer bills		481	479	478	480	481	481	481
593	Demand		2,695	2,670	2,649	2,638	2,605	2,605	2,596
594	Usage		614,686	498,276	424,376	392,391	393,195	509,639	553,323
595	Usage per Customer		1,278	1,040	888	817	817	1,060	1,150
596	PB Base Rate Revenue		25,118	20,940	18,470	17,120	18,699	23,335	25,107
597	PB Fuel Rider Revenue		23,415	15,558	12,833	12,369	15,296	14,794	17,545
598	PB Other Rider Revenue		7,381	6,071	4,964	4,796	4,921	6,308	6,571
599	Total PB Retail Sales Revenue		55,914	42,569	36,267	34,286	38,916	44,437	49,223
600									
601	MUNI PUMPING-SEC-CONJUNCTIVE	549							
602	Customer bills		-	-	-	-	-	-	-
603	Demand		-	-	-	-	-	-	-
604	Usage		-	-	-	-	-	-	-
605	Usage per Customer		-	-	-	-	-	-	-
606	PB Base Rate Revenue		-	-	-	-	-	-	-
607	PB Fuel Rider Revenue		-	-	-	-	-	-	-
608	PB Other Rider Revenue		-	-	-	-	-	-	-
609	Total PB Retail Sales Revenue		-	-	-	-	-	-	-
610									
611	MUNI PUMPING-YR2-SEC-NONCONJUNCTIVE	550							
612	Customer bills		207	208	210	210	209	206	208
613	Demand		3,930	3,957	3,903	3,901	3,969	4,135	3,817
614	Usage		1,062,483	986,092	993,086	854,746	896,170	1,098,662	882,630
615	Usage per Customer		5,133	4,741	4,729	4,070	4,288	5,333	4,243
616	PB Base Rate Revenue		34,229	32,667	32,196	28,166	33,497	40,760	30,338
617	PB Fuel Rider Revenue		40,472	30,790	30,032	26,943	34,863	31,891	27,986
618	PB Other Rider Revenue		12,205	10,854	11,586	9,877	10,524	12,877	12,716
619	Total PB Retail Sales Revenue		86,907	74,310	73,814	64,986	78,883	85,529	71,041
620									
621	ARKANSAS TOTALS								
622	Customer bills		149,908	150,143	150,080	150,075	150,107	150,005	150,241
623	Demand		528,717	526,000	527,660	530,156	569,596	592,990	599,002
624	Usage		341,237,384	309,753,759	283,610,288	278,633,516	284,696,023	363,780,700	386,312,527
625	Usage per Customer		2,276	2,063	1,890	1,857	1,897	2,425	2,571
626	PB Base Rate Revenue		10,101,798	9,277,438	8,491,217	8,032,090	11,584,720	14,380,252	15,421,799
627	PB Fuel Rider Revenue		12,902,209	9,583,780	8,481,970	8,675,706	10,974,484	10,453,167	12,133,758
628	PB Other Rider Revenue		3,880,269	3,480,900	3,030,296	2,940,728	3,259,861	4,241,999	4,318,402
629	Total PB Retail Sales Revenue		26,884,276	22,342,117	20,003,483	19,648,524	25,819,065	29,075,418	31,873,959

Supporting Schedules
WP G-3

Line No.	Rate Schedule		Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	12 Month Total
580								
581	MUNI PUMPING-YR2-SECONDARY	540						
582	Customer bills		63	63	60	64	63	758
583	Demand		549	549	549	549	549	20,074
584	Usage		274,421	279,533	229,801	244,157	269,560	3,577,764
585	Usage per Customer		4,367	4,445	3,807	3,813	4,256	56,512
586	PB Base Rate Revenue		2,384	2,201	4,730	8,601	9,657	104,632
587	PB Fuel Rider Revenue		2,013	1,779	6,038	8,131	8,235	101,579
588	PB Other Rider Revenue		2,895	2,323	6,401	7,344	11,698	57,003
589	Total PB Retail Sales Revenue		7,292	6,304	17,169	24,077	29,589	263,214
590								
591	MUNI SERVICE-YEAR 2-SECONDARY	544						
592	Customer bills		476	474	484	480	483	5,758
593	Demand		2,577	2,556	2,560	2,559	2,559	31,268
594	Usage		547,522	516,166	423,281	398,575	484,946	5,756,376
595	Usage per Customer		1,151	1,089	875	830	1,005	12,000
596	PB Base Rate Revenue		23,941	21,354	11,328	18,678	22,181	246,270
597	PB Fuel Rider Revenue		16,152	13,647	11,122	13,274	14,815	180,819
598	PB Other Rider Revenue		24,393	18,783	12,576	12,912	22,657	132,333
599	Total PB Retail Sales Revenue		64,485	53,784	35,025	44,864	59,653	559,423
600								
601	MUNI PUMPING-SEC-CONJUNCTIVE	549						
602	Customer bills		11	11	-	-	-	22
603	Demand		888	947	756	1,199	1,199	4,989
604	Usage		-	-	-	-	-	-
605	Usage per Customer		-	-	-	-	-	-
606	PB Base Rate Revenue		7,319	7,136	-	-	-	14,456
607	PB Fuel Rider Revenue		6,010	5,677	-	-	-	11,687
608	PB Other Rider Revenue		8,773	7,354	-	-	-	16,126
609	Total PB Retail Sales Revenue		22,102	20,167	-	-	-	42,268
610								
611	MUNI PUMPING-YR2-SEC-NONCONJUNCTIVE	550						
612	Customer bills		210	207	208	207	208	2,499
613	Demand		4,596	4,246	4,337	4,346	4,346	49,483
614	Usage		1,365,826	1,158,983	944,125	945,676	1,073,956	12,262,435
615	Usage per Customer		6,489	5,609	4,533	4,567	5,160	58,895
616	PB Base Rate Revenue		51,269	38,622	19,320	33,080	37,513	411,658
617	PB Fuel Rider Revenue		40,292	30,643	24,807	31,494	32,808	383,021
618	PB Other Rider Revenue		46,262	40,138	26,269	28,432	46,991	268,731
619	Total PB Retail Sales Revenue		137,824	109,403	70,395	93,005	117,313	1,063,410
620								
621	ARKANSAS TOTALS							
622	Customer bills		150,434	150,490	150,427	150,547	150,754	1,803,211
623	Demand		617,068	600,366	580,755	563,955	563,955	6,800,218
624	Usage		390,612,814	376,398,064	313,600,501	279,546,720	306,863,707	3,915,046,003
625	Usage per Customer		2,597	2,501	2,085	1,857	2,036	26,054
626	PB Base Rate Revenue		15,586,011	13,166,467	5,736,178	8,794,078	10,638,453	131,210,502
627	PB Fuel Rider Revenue		11,966,285	9,622,705	8,236,824	9,283,704	9,793,936	122,108,527
628	PB Other Rider Revenue		9,677,283	7,873,167	4,961,229	5,334,482	7,663,986	60,662,601
629	Total PB Retail Sales Revenue		37,229,579	30,662,339	18,934,231	23,412,263	28,096,375	313,981,629

Supporting Schedules
WP G-3

SOUTHWESTERN ELECTRIC POWER COMPANY
ARKANSAS JURISDICTIONAL
BILLING DETERMINANTS - PRO FORMA YEAR 2019

Line No.	Rate Schedule		Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19
1	RESIDENTIAL SERVICE	15							
2	Customer bills		87,504	87,504	87,504	87,504	87,504	87,504	87,504
3	Demand		5,626	5,459	5,296	5,001	5,358	5,378	5,382
4	Usage		90,863,587	82,567,063	69,682,129	57,858,228	52,665,986	79,276,597	102,034,457
5	Usage per Customer		1,038	944	796	661	602	906	1,166
6									
7	RESIDENTIAL-ELECTRIC HTG APPLIANCE	22							
8	Customer bills		13,875	13,875	13,875	13,875	13,875	13,875	13,875
9	Demand		1,801	1,725	1,549	1,373	1,332	1,223	1,206
10	Usage		25,307,421	22,920,470	17,849,266	13,787,093	11,045,762	14,609,324	18,174,948
11	Usage per Customer		1,824	1,652	1,286	994	796	1,053	1,310
12									
13	RESIDENTIAL-MULTIPLE DWELLING	38							
14	Customer bills		35	35	35	35	35	35	35
15	Demand		82	82	65	60	47	47	53
16	Usage		47,085	45,038	33,285	27,972	17,122	21,337	29,240
17	Usage per Customer		1,335	1,277	944	793	485	605	829
18									
19	RESIDENTIAL-ELECT HT-MULTI DWELLING	39							
20	Customer bills		37	37	37	37	37	37	37
21	Demand		262	366	306	231	228	170	160
22	Usage		84,108	95,114	87,728	73,377	64,548	45,900	50,582
23	Usage per Customer		2,255	2,551	2,353	1,968	1,731	1,231	1,356
24									
25	MASTER MTRD-GENERAL SERV-YEAR 2	50							
26	Customer bills		5	5	5	5	5	5	5
27	Demand		93	100	68	53	57	69	67
28	Usage		41,528	40,570	34,016	29,278	25,423	33,205	37,431
29	Usage per Customer		8,241	8,051	6,750	5,810	5,045	6,589	7,428
30									
31	MASTER MTRD-LTG & PWR-YR2-SECONDARY	60							
32	Customer bills		2	2	2	2	2	2	2
33	Demand		223	223	223	223	226	226	240
34	Usage		71,752	69,311	62,079	60,228	47,746	83,051	96,956
35	Usage per Customer		35,596	34,385	30,797	29,879	23,687	41,202	48,100
36									
37	RESIDENTIAL NET-METERING	62							
38	Customer bills		53	53	53	53	53	53	53
39	Demand		-	-	-	-	-	-	-
40	Usage		49,744	42,849	37,150	27,540	20,910	33,869	42,082
41	Usage per Customer		931	802	695	516	391	634	788
42									
43	MASTER MTRD-LTG & PWR-YR 2-PRIMARY	66							
44	Customer bills		2	2	2	2	2	2	2
45	Demand		719	1,204	874	874	889	907	914
46	Usage		252,980	244,755	147,296	112,347	102,496	169,608	200,771
47	Usage per Customer		125,503	121,423	73,073	55,735	50,848	84,143	99,602
48									
49	8000L MV PL ON EXISTING POLE	91							
50	Customer bills		2,296	2,296	2,296	2,296	2,296	2,296	2,296
51	Demand		-	-	-	-	-	-	-
52	Usage		154,882	154,791	154,151	154,004	155,138	155,159	154,369
53	Usage per Customer		67	67	67	67	68	68	67
54									
55	8000L MV PL ON WOOD POLE	92							
56	Customer bills		810	810	810	810	810	810	810
57	Demand		-	-	-	-	-	-	-
58	Usage		54,677	54,575	54,419	54,365	54,400	54,580	53,722
59	Usage per Customer		68	67	67	67	67	67	66
60									
61	175W MV OUTDOOR LIGHTING	93							
62	Customer bills		245	245	245	245	245	245	245
63	Demand		-	-	-	-	-	-	-
64	Usage		16,073	16,482	16,636	16,543	16,593	16,443	16,326
65	Usage per Customer		66	67	68	68	68	67	67
66									
67	100W MV AREA LIGHTING	94							
68	Customer bills		3	3	3	3	3	3	3
69	Demand		-	-	-	-	-	-	-
70	Usage		126	126	126	126	126	126	126
71	Usage per Customer		42	42	42	42	42	42	42
72									
73	400W MV OUTDOOR LIGHTING	95							
74	Customer bills		9	9	9	9	9	9	9
75	Demand		-	-	-	-	-	-	-
76	Usage		1,395	1,395	1,395	1,395	1,395	1,395	1,395
77	Usage per Customer		155	155	155	155	155	155	155
78									
79	400W MV AREA LIGHTING	96							
80	Customer bills		65	65	65	65	65	65	65
81	Demand		-	-	-	-	-	-	-
82	Usage		10,075	10,075	9,942	9,937	10,075	10,037	9,965
83	Usage per Customer		155	155	153	153	155	154	153
84									
85	100W HPS OUTDOOR LIGHTING	97							
86	Customer bills		3,743	3,743	3,743	3,743	3,743	3,743	3,743
87	Demand		-	-	-	-	-	-	-
88	Usage		181,717	181,437	181,526	181,775	181,181	182,159	181,872
89	Usage per Customer		49	48	48	49	48	49	49
90									
91	100W HPS AREA LIGHTING	98							
92	Customer bills		2,466	2,466	2,466	2,466	2,466	2,466	2,466
93	Demand		-	-	-	-	-	-	-
94	Usage		119,724	118,652	118,308	120,093	120,527	119,908	119,774
95	Usage per Customer		49	48	48	49	49	49	49

Line No.	Rate Schedule		Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	12 Month Total
1	RESIDENTIAL SERVICE	15						
2	Customer bills		87,504	87,504	87,504	87,504	87,504	1,050,044
3	Demand		5,416	5,472	5,390	5,302	5,286	64,364
4	Usage		108,783,553	101,494,227	71,227,910	57,659,512	76,132,018	950,245,266
5	Usage per Customer		1,243	1,160	814	659	870	10,859
6								
7	RESIDENTIAL-ELECTRIC HTG APPLIANCE	22						
8	Customer bills		13,875	13,875	13,875	13,875	13,875	166,503
9	Demand		1,230	1,202	1,041	1,143	1,150	15,975
10	Usage		19,576,589	18,492,111	13,223,727	12,372,753	18,608,918	205,968,382
11	Usage per Customer		1,411	1,333	953	892	1,341	14,844
12								
13	RESIDENTIAL-MULTIPLE DWELLING	38						
14	Customer bills		35	35	35	35	35	423
15	Demand		46	55	55	63	56	712
16	Usage		27,046	25,588	20,288	24,204	31,324	349,529
17	Usage per Customer		767	725	575	686	888	9,909
18								
19	RESIDENTIAL-ELECT HT-MULTI DWELLING	39						
20	Customer bills		37	37	37	37	37	447
21	Demand		162	216	220	190	190	2,701
22	Usage		54,423	79,315	70,689	60,373	74,778	840,935
23	Usage per Customer		1,459	2,127	1,896	1,619	2,005	22,551
24								
25	MASTER MTRD-GENERAL SERV-YEAR 2	50						
26	Customer bills		5	5	5	5	5	60
27	Demand		67	68	67	45	45	799
28	Usage		40,900	42,772	35,199	27,521	33,389	421,233
29	Usage per Customer		8,116	8,488	6,985	5,461	6,626	83,589
30								
31	MASTER MTRD-LTG & PWR-YR2-SECONDARY	60						
32	Customer bills		2	2	2	2	2	24
33	Demand		241	270	230	203	203	2,728
34	Usage		100,038	107,815	81,193	57,567	61,943	899,680
35	Usage per Customer		49,629	53,487	40,280	28,559	30,730	446,330
36								
37	RESIDENTIAL NET-METERING	62						
38	Customer bills		53	53	53	53	53	641
39	Demand		-	-	-	-	-	-
40	Usage		54,403	52,500	33,466	26,671	35,903	457,087
41	Usage per Customer		1,018	983	627	499	672	8,557
42								
43	MASTER MTRD-LTG & PWR-YR 2-PRIMARY	66						
44	Customer bills		2	2	2	2	2	24
45	Demand		906	1,402	132	101	101	9,023
46	Usage		301,014	204,865	164,504	113,046	148,237	2,161,919
47	Usage per Customer		149,333	101,633	81,610	56,082	73,540	1,072,526
48								
49	8000L MV PL ON EXISTING POLE	91						
50	Customer bills		2,296	2,296	2,296	2,296	2,296	27,552
51	Demand		-	-	-	-	-	-
52	Usage		162,594	161,709	157,660	167,989	175,561	1,908,005
53	Usage per Customer		71	70	69	73	76	831
54								
55	8000L MV PL ON WOOD POLE	92						
56	Customer bills		810	810	810	810	810	9,720
57	Demand		-	-	-	-	-	-
58	Usage		54,661	56,572	56,186	60,776	63,236	672,168
59	Usage per Customer		67	70	69	75	78	830
60								
61	175W MV OUTDOOR LIGHTING	93						
62	Customer bills		245	245	245	245	245	2,940
63	Demand		-	-	-	-	-	-
64	Usage		17,521	17,290	16,539	17,702	18,815	202,962
65	Usage per Customer		72	71	68	72	77	828
66								
67	100W MV AREA LIGHTING	94						
68	Customer bills		3	3	3	3	3	36
69	Demand		-	-	-	-	-	-
70	Usage		134	132	119	127	139	1,534
71	Usage per Customer		45	44	40	42	46	511
72								
73	400W MV OUTDOOR LIGHTING	95						
74	Customer bills		9	9	9	9	9	108
75	Demand		-	-	-	-	-	-
76	Usage		1,439	1,436	1,348	1,276	1,283	16,545
77	Usage per Customer		160	160	150	142	143	1,838
78								
79	400W MV AREA LIGHTING	96						
80	Customer bills		65	65	65	65	65	780
81	Demand		-	-	-	-	-	-
82	Usage		10,408	10,292	10,544	11,161	11,372	123,882
83	Usage per Customer		160	158	162	172	175	1,906
84								
85	100W HPS OUTDOOR LIGHTING	97						
86	Customer bills		3,743	3,743	3,743	3,743	3,743	44,916
87	Demand		-	-	-	-	-	-
88	Usage		191,047	189,617	164,830	173,451	187,353	2,177,963
89	Usage per Customer		51	51	44	46	50	582
90								
91	100W HPS AREA LIGHTING	98						
92	Customer bills		2,466	2,466	2,466	2,466	2,466	29,592
93	Demand		-	-	-	-	-	-
94	Usage		126,539	124,976	117,247	123,003	133,456	1,462,208
95	Usage per Customer		51	51	48	50	54	593

SOUTHWESTERN ELECTRIC POWER COMPANY
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Line No.	Rate Schedule		Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19
96									
97	250W HPS OUTDOOR LIGHTING	103							
98	Customer bills		131	131	131	131	131	131	131
99	Demand		-	-	-	-	-	-	-
100	Usage		13,755	13,733	13,755	13,604	13,681	13,755	13,664
101	Usage per Customer		105	105	105	104	104	105	104
102									
103	250W HPS AREA LIGHTING	104							
104	Customer bills		78	78	78	78	78	78	78
105	Demand		-	-	-	-	-	-	-
106	Usage		8,190	8,190	8,093	8,081	8,190	8,190	8,190
107	Usage per Customer		105	105	104	104	105	105	105
108									
109	400W HPS OUTDOOR LIGHTING	107							
110	Customer bills		899	899	899	899	899	899	899
111	Demand		-	-	-	-	-	-	-
112	Usage		147,218	147,782	146,003	147,884	147,925	148,192	147,913
113	Usage per Customer		164	164	162	164	165	165	165
114									
115	400W HPS AREA LIGHTING	108							
116	Customer bills		1,023	1,023	1,023	1,023	1,023	1,023	1,023
117	Demand		-	-	-	-	-	-	-
118	Usage		168,255	168,207	168,229	168,642	168,513	166,329	167,616
119	Usage per Customer		164	164	164	165	165	163	164
120									
121	1000W HPS OUTDOOR LIGHTING	111							
122	Customer bills		645	645	645	645	645	645	645
123	Demand		-	-	-	-	-	-	-
124	Usage		250,206	247,742	250,064	249,032	249,398	247,671	248,109
125	Usage per Customer		388	384	388	386	387	384	385
126									
127	1000W HPS AREA LIGHTING	112							
128	Customer bills		647	647	647	647	647	647	647
129	Demand		-	-	-	-	-	-	-
130	Usage		249,897	250,370	247,488	250,446	249,993	251,296	250,507
131	Usage per Customer		386	387	383	387	386	388	387
132									
133	70W HPS AREA LIGHTING	115							
134	Customer bills		1	1	1	1	1	1	1
135	Demand		-	-	-	-	-	-	-
136	Usage		35	35	35	35	35	35	35
137	Usage per Customer		35	35	35	35	35	35	35
138									
139	400W MH AREA LIGHTING	132							
140	Customer bills		812	812	812	812	812	812	812
141	Demand		-	-	-	-	-	-	-
142	Usage		126,330	126,456	125,430	124,204	126,460	123,774	126,459
143	Usage per Customer		156	156	154	153	156	152	156
144									
145	400W MH OUTDOOR LIGHTING	133							
146	Customer bills		695	695	695	695	695	695	695
147	Demand		-	-	-	-	-	-	-
148	Usage		107,370	106,919	108,025	108,156	108,124	107,706	107,343
149	Usage per Customer		154	154	155	156	156	155	154
150									
151	1000W MH AREA LIGHTING	135							
152	Customer bills		666	666	666	666	666	666	666
153	Demand		-	-	-	-	-	-	-
154	Usage		248,284	247,657	245,897	245,622	246,887	242,772	247,549
155	Usage per Customer		373	372	369	369	371	365	372
156									
157	1000W MH OUTDOOR LIGHTING	136							
158	Customer bills		866	866	866	866	866	866	866
159	Demand		-	-	-	-	-	-	-
160	Usage		320,780	319,361	309,374	321,241	322,461	321,800	319,282
161	Usage per Customer		370	369	357	371	372	372	369
162									
163	175W MV AREA LIGHTING	137							
164	Customer bills		335	335	335	335	335	335	335
165	Demand		-	-	-	-	-	-	-
166	Usage		22,762	22,706	22,054	22,780	22,406	22,723	21,819
167	Usage per Customer		68	68	66	68	67	68	65
168									
169	250W MV AREA LIGHTING	138							
170	Customer bills		25	25	25	25	25	25	25
171	Demand		-	-	-	-	-	-	-
172	Usage		2,450	2,500	2,450	2,450	2,450	2,450	2,450
173	Usage per Customer		98	100	98	98	98	98	98
174									
175	1000W MV AREA LIGHTING	140							
176	Customer bills		8	8	8	8	8	8	8
177	Demand		-	-	-	-	-	-	-
178	Usage		2,912	2,912	2,912	2,912	2,912	2,912	2,912
179	Usage per Customer		364	364	364	364	364	364	364
180									
181	GEN SVC-YR 2 W/C2 RIDER-1 MTR CHG	200							
182	Customer bills		287	287	287	287	287	287	287
183	Demand		3,567	3,528	3,449	3,336	4,345	3,268	3,412
184	Usage		1,240,503	1,136,846	797,183	632,044	550,730	806,279	946,906
185	Usage per Customer		4,329	3,968	2,782	2,206	1,922	2,814	3,305
186									
187	UNMETERED GENERAL SERVICE	202							
188	Customer bills		8	8	8	8	8	8	8
189	Demand		-	-	-	-	-	-	-
190	Usage		2,315	2,315	2,315	2,315	2,315	2,315	2,315
191	Usage per Customer		288	288	288	288	288	288	288
192									
193	RECREATIONAL LIGHTING	204							
194	Customer bills		106	106	106	106	106	106	106
195	Demand		1,990	2,799	5,638	6,621	6,551	5,178	4,233
196	Usage		336,848	317,660	343,390	356,870	344,711	284,741	243,871
197	Usage per Customer		3,191	3,009	3,253	3,380	3,265	2,697	2,310
198									
199	GENERAL SERVICE - YEAR 2	220							
200	Customer bills		14,458	14,458	14,458	14,458	14,458	14,458	14,458
201	Demand		57,381	56,990	56,751	57,956	68,634	79,188	83,022

Line No.	Rate Schedule		Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	12 Month Total
96								
97	250W HPS OUTDOOR LIGHTING	103						
98	Customer bills		131	131	131	131	131	1,572
99	Demand		-	-	-	-	-	-
100	Usage		14,244	14,372	12,608	13,126	13,779	164,076
101	Usage per Customer		109	110	96	100	105	1,252
102								
103	250W HPS AREA LIGHTING	104						
104	Customer bills		78	78	78	78	78	936
105	Demand		-	-	-	-	-	-
106	Usage		8,489	8,423	7,913	8,399	8,553	98,902
107	Usage per Customer		109	108	101	108	110	1,268
108								
109	400W HPS OUTDOOR LIGHTING	107						
110	Customer bills		899	899	899	899	899	10,788
111	Demand		-	-	-	-	-	-
112	Usage		152,330	151,862	131,698	140,445	144,785	1,754,037
113	Usage per Customer		169	169	146	156	161	1,951
114								
115	400W HPS AREA LIGHTING	108						
116	Customer bills		1,023	1,023	1,023	1,023	1,023	12,276
117	Demand		-	-	-	-	-	-
118	Usage		173,981	172,404	160,829	176,691	177,913	2,037,608
119	Usage per Customer		170	169	157	173	174	1,992
120								
121	1000W HPS OUTDOOR LIGHTING	111						
122	Customer bills		645	645	645	645	645	7,740
123	Demand		-	-	-	-	-	-
124	Usage		250,217	254,764	225,428	233,129	236,153	2,941,913
125	Usage per Customer		388	395	350	361	366	4,561
126								
127	1000W HPS AREA LIGHTING	112						
128	Customer bills		647	647	647	647	647	7,764
129	Demand		-	-	-	-	-	-
130	Usage		258,686	255,131	247,254	268,256	268,352	3,047,676
131	Usage per Customer		400	394	382	415	415	4,710
132								
133	70W HPS AREA LIGHTING	115						
134	Customer bills		1	1	1	1	1	12
135	Demand		-	-	-	-	-	-
136	Usage		36	36	34	36	36	423
137	Usage per Customer		36	36	34	36	36	423
138								
139	400W MH AREA LIGHTING	132						
140	Customer bills		812	812	812	812	812	9,744
141	Demand		-	-	-	-	-	-
142	Usage		130,170	129,975	129,637	137,482	137,393	1,543,770
143	Usage per Customer		160	160	160	169	169	1,901
144								
145	400W MH OUTDOOR LIGHTING	133						
146	Customer bills		695	695	695	695	695	8,340
147	Demand		-	-	-	-	-	-
148	Usage		109,883	109,723	101,900	107,703	108,340	1,291,192
149	Usage per Customer		158	158	147	155	156	1,858
150								
151	1000W MH AREA LIGHTING	135						
152	Customer bills		666	666	666	666	666	7,992
153	Demand		-	-	-	-	-	-
154	Usage		254,809	252,914	249,731	274,521	268,817	3,025,462
155	Usage per Customer		383	380	375	412	404	4,543
156								
157	1000W MH OUTDOOR LIGHTING	136						
158	Customer bills		866	866	866	866	866	10,392
159	Demand		-	-	-	-	-	-
160	Usage		333,112	326,588	299,592	308,870	311,671	3,814,132
161	Usage per Customer		385	377	346	357	360	4,404
162								
163	175W MV AREA LIGHTING	137						
164	Customer bills		335	335	335	335	335	4,020
165	Demand		-	-	-	-	-	-
166	Usage		23,686	23,374	25,140	26,578	27,027	283,055
167	Usage per Customer		71	70	75	79	81	845
168								
169	250W MV AREA LIGHTING	138						
170	Customer bills		25	25	25	25	25	300
171	Demand		-	-	-	-	-	-
172	Usage		2,527	2,521	2,462	2,622	2,636	29,966
173	Usage per Customer		101	101	98	105	105	1,199
174								
175	1000W MV AREA LIGHTING	140						
176	Customer bills		8	8	8	8	8	96
177	Demand		-	-	-	-	-	-
178	Usage		2,992	2,891	2,200	8,290	8,146	44,902
179	Usage per Customer		374	361	275	1,036	1,018	5,613
180								
181	GEN SVC-YR 2 W/C2 RIDER-1 MTR CHG	200						
182	Customer bills		287	287	287	287	287	3,438
183	Demand		3,350	3,349	3,162	3,324	3,285	41,376
184	Usage		997,935	922,008	695,908	584,616	710,735	10,021,693
185	Usage per Customer		3,483	3,218	2,429	2,040	2,480	34,975
186								
187	UNMETERED GENERAL SERVICE	202						
188	Customer bills		8	8	8	8	8	97
189	Demand		-	-	-	-	-	-
190	Usage		2,393	2,386	2,223	2,380	2,381	27,964
191	Usage per Customer		297	297	276	296	296	3,477
192								
193	RECREATIONAL LIGHTING	204						
194	Customer bills		106	106	106	106	106	1,267
195	Demand		4,216	5,140	5,879	5,388	5,310	58,943
196	Usage		240,953	273,650	285,304	297,293	245,892	3,571,182
197	Usage per Customer		2,282	2,592	2,702	2,816	2,329	33,827
198								
199	GENERAL SERVICE - YEAR 2	220						
200	Customer bills		14,458	14,458	14,458	14,458	14,458	173,494
201	Demand		83,579	80,079	78,089	62,542	62,346	826,557

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Line No.	Rate Schedule		Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19
202	Usage		25,968,854	23,905,128	21,906,805	21,659,719	21,804,076	30,455,749	34,444,581
203	Usage per Customer		1,796	1,653	1,515	1,498	1,508	2,107	2,382
204									
205	GENERAL SERVICE-YEAR 2 W/C2 RIDER	222							
206	Customer bills		1,239	1,239	1,239	1,239	1,239	1,239	1,239
207	Demand		11,103	11,105	10,284	9,874	12,084	9,815	10,124
208	Usage		5,231,836	4,666,215	3,629,079	3,130,789	2,744,691	3,585,815	4,012,186
209	Usage per Customer		4,224	3,768	2,930	2,528	2,216	2,895	3,239
210									
211	LTG & POWER-TIME OF USE-SECONDARY	223							
212	Customer bills		2	2	2	2	2	2	2
213	Demand		2,678	2,825	3,482	2,731	3,040	3,011	2,699
214	Usage		488,129	492,583	524,284	563,079	627,497	485,231	520,094
215	Usage per Customer		244,474	246,705	262,582	282,012	314,275	243,023	260,484
216									
217	LTG & POWER-TIME OF USE-PRIMARY	225							
218	Customer bills		1	1	1	1	1	1	1
219	Demand		2,322	2,752	2,751	2,436	2,844	2,457	2,493
220	Usage		1,393,402	1,368,806	1,491,059	1,433,533	1,573,506	1,511,204	1,276,482
221	Usage per Customer		1,385,867	1,361,404	1,482,996	1,425,781	1,564,997	1,503,032	1,269,579
222									
223	LTG & POWER-YEAR 2-SECONDARY	240							
224	Customer bills		1,281	1,281	1,281	1,281	1,281	1,281	1,281
225	Demand		197,528	196,558	195,570	196,714	205,091	219,660	217,797
226	Usage		68,224,729	64,692,913	64,882,423	64,819,788	65,661,102	79,735,124	83,040,895
227	Usage per Customer		53,273	50,516	50,664	50,615	51,272	62,261	64,843
228									
229	LTG & PWR-YR 2-SECONDARY W/C2 RIDER	243							
230	Customer bills		330	330	330	330	330	330	330
231	Demand		46,040	46,368	42,778	43,733	45,767	48,307	50,350
232	Usage		19,515,462	17,463,124	16,258,587	15,374,139	15,039,520	18,479,517	19,517,164
233	Usage per Customer		59,206	52,980	49,325	46,642	45,627	56,063	59,211
234									
235	LTG & POWER-YEAR 2-PRIMARY	246							
236	Customer bills		34	34	34	34	34	34	34
237	Demand		57,886	59,540	64,683	66,139	69,638	67,359	72,666
238	Usage		26,829,158	29,665,370	29,107,514	31,860,487	33,238,643	33,367,960	34,674,948
239	Usage per Customer		788,105	871,419	855,032	935,900	976,383	980,182	1,018,575
240									
241	LTG & PWR-YR 2-PRIMARY W/C2 RIDER	249							
242	Customer bills		10	10	10	10	10	10	10
243	Demand		21,605	21,500	21,343	18,758	26,310	23,393	23,455
244	Usage		9,992,744	10,056,842	9,040,330	9,804,386	10,050,499	11,332,335	11,247,074
245	Usage per Customer		999,527	1,005,938	904,261	980,686	1,005,304	1,133,520	1,124,992
246									
247	LTG & PWR-YR 2-PRI W/SEC FUEL & C2	250							
248	Customer bills		2	2	2	2	2	2	2
249	Demand		918	800	705	710	785	866	965
250	Usage		410,332	329,142	244,368	244,355	254,451	352,126	444,942
251	Usage per Customer		204,056	163,681	121,523	121,517	126,538	175,111	221,268
252									
253	LTG & PWR-YEAR 2-PRIMARY@SUBSTATION	251							
254	Customer bills		1	1	1	1	1	1	1
255	Demand		6,974	6,345	6,345	6,160	5,997	6,011	6,198
256	Usage		2,328,892	2,041,375	1,883,240	1,868,864	1,883,240	1,854,488	1,926,368
257	Usage per Customer		2,332,800	2,044,800	1,886,400	1,872,000	1,886,400	1,857,600	1,929,600
258									
259	GS SECONDARY NET-METERING	282							
260	Customer bills		9	9	9	9	9	9	9
261	Demand		80	85	78	61	95	150	156
262	Usage		22,674	26,591	21,968	21,302	16,305	22,712	32,412
263	Usage per Customer		2,506	2,939	2,428	2,354	1,802	2,510	3,582
264									
265	LTG & PWR-SEC NET-METERING	292							
266	Customer bills		4	4	4	4	4	4	4
267	Demand		910	931	1,003	920	922	1,009	1,009
268	Usage		324,518	326,527	347,504	321,355	326,025	419,644	425,577
269	Usage per Customer		80,691	81,190	86,406	79,904	81,066	104,344	105,819
270									
271	LLP PRIMARY W/ SBMAA	319							
272	Customer bills		1	1	1	1	1	1	1
273	Demand		13,381	13,381	13,381	13,381	15,130	15,709	15,996
274	Usage		5,819,615	5,334,962	7,324,698	7,575,171	7,318,327	7,186,627	7,644,773
275	Usage per Customer		5,788,145	5,306,113	7,285,090	7,534,208	7,278,753	7,147,765	7,603,434
276									
277	PULP & PAPER MILL SERVICE-DOMTAR	326							
278	Customer bills		1	1	1	1	1	1	1
279	Demand		38,092	38,092	38,092	38,092	38,092	38,092	37,982
280	Usage		17,958,657	15,564,150	20,393,395	18,870,544	20,302,250	23,429,492	24,398,896
281	Usage per Customer		17,988,789	15,590,264	20,427,612	18,902,206	20,336,314	23,468,803	24,439,834
282									
283	LTG&PWR-PRIMARY-CURTAILABLE DEMAND	336							
284	Customer bills		5	5	5	5	5	5	5
285	Demand		15,011	14,502	14,330	14,445	14,562	14,008	14,176
286	Usage		2,633,421	2,470,998	2,359,681	2,502,253	2,462,979	2,506,865	2,303,968
287	Usage per Customer		525,322	492,922	470,716	499,157	491,322	500,077	459,602
288									
289	LARGE LTG & POWER-YR 2-TRANS 69 KV	342							
290	Customer bills		1	1	1	1	1	1	1
291	Demand		21,288	21,262	21,798	21,493	21,900	21,862	22,378
292	Usage		11,336,920	11,560,432	12,763,322	13,627,834	12,976,604	13,310,879	13,519,306
293	Usage per Customer		11,355,942	11,579,829	12,784,737	13,650,699	12,998,377	13,333,213	13,541,989
294									
295	LARGE LTG & POWER-YEAR 2-PRIMARY	346							
296	Customer bills		1	1	1	1	1	1	1
297	Demand		11,699	11,305	11,435	11,762	12,990	13,211	13,646
298	Usage		7,084,503	7,450,646	7,087,982	7,703,907	7,797,161	8,563,297	8,465,126
299	Usage per Customer		7,096,390	7,463,147	7,099,875	7,716,833	7,810,243	8,577,665	8,479,329
300									

Line No.	Rate Schedule		Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	12 Month Total
202	Usage		35,491,128	33,845,984	27,016,441	22,540,739	23,380,580	322,419,788
203	Usage per Customer		2,455	2,341	1,869	1,559	1,617	22,301
204								
205	GENERAL SERVICE-YEAR 2 W/C2 RIDER	222						
206	Customer bills		1,239	1,239	1,239	1,239	1,239	14,863
207	Demand		9,964	9,955	9,353	9,697	9,603	122,960
208	Usage		4,106,853	3,944,192	3,169,010	2,904,560	3,385,381	44,510,608
209	Usage per Customer		3,316	3,185	2,559	2,345	2,733	35,938
210								
211	LTG & POWER-TIME OF USE-SECONDARY	223						
212	Customer bills		2	2	2	2	2	24
213	Demand		2,694	3,074	4,785	828	832	32,677
214	Usage		520,042	505,253	581,955	456,658	502,771	6,267,577
215	Usage per Customer		260,457	253,050	291,466	228,712	251,807	3,139,046
216								
217	LTG & POWER-TIME OF USE-PRIMARY	225						
218	Customer bills		1	1	1	1	1	12
219	Demand		2,762	-	5,963	2,828	2,814	32,422
220	Usage		1,349,923	1,139,950	1,453,568	1,406,614	1,433,501	16,831,547
221	Usage per Customer		1,342,623	1,133,786	1,445,708	1,399,007	1,425,749	16,740,530
222								
223	LTG & POWER-YEAR 2-SECONDARY	240						
224	Customer bills		1,281	1,281	1,281	1,281	1,281	15,368
225	Demand		226,332	223,793	218,379	202,912	207,254	2,507,589
226	Usage		85,707,466	84,329,874	77,919,338	68,599,300	70,997,200	878,610,151
227	Usage per Customer		66,925	65,849	60,843	53,566	55,438	686,065
228								
229	LTG & PWR-YR 2-SECONDARY W/C2 RIDER	243						
230	Customer bills		330	330	330	330	330	3,955
231	Demand		49,815	49,709	47,629	44,680	46,115	561,291
232	Usage		20,272,075	19,884,076	17,206,356	15,752,328	17,151,286	211,913,632
233	Usage per Customer		61,501	60,324	52,201	47,789	52,034	642,903
234								
235	LTG & POWER-YEAR 2-PRIMARY	246						
236	Customer bills		34	34	34	34	34	409
237	Demand		73,485	75,559	75,824	68,677	66,714	818,169
238	Usage		37,079,601	37,919,112	33,160,546	31,709,907	31,341,439	389,954,684
239	Usage per Customer		1,089,211	1,113,872	974,089	931,477	920,653	11,454,898
240								
241	LTG & PWR-YR 2-PRIMARY W/C2 RIDER	249						
242	Customer bills		10	10	10	10	10	120
243	Demand		23,352	23,078	22,693	20,781	20,844	267,110
244	Usage		11,383,155	11,227,051	10,604,931	10,446,939	10,907,271	126,093,556
245	Usage per Customer		1,138,603	1,122,989	1,060,761	1,044,958	1,091,003	12,612,542
246								
247	LTG & PWR-YR 2-PRI W/SEC FUEL & C2	250						
248	Customer bills		2	2	2	2	2	24
249	Demand		969	871	874	721	718	9,902
250	Usage		394,863	387,094	308,073	235,662	298,612	3,904,019
251	Usage per Customer		196,364	192,500	153,204	117,194	148,498	1,941,454
252								
253	LTG & PWR-YEAR 2-PRIMARY@SUBSTATION	251						
254	Customer bills		1	1	1	1	1	12
255	Demand		6,030	5,981	6,164	5,987	6,017	74,210
256	Usage		1,935,635	1,782,488	2,264,177	2,217,747	2,408,069	24,394,585
257	Usage per Customer		1,938,883	1,785,478	2,267,976	2,221,468	2,412,110	24,435,516
258								
259	GS SECONDARY NET-METERING	282						
260	Customer bills		9	9	9	9	9	109
261	Demand		153	149	192	123	122	1,444
262	Usage		43,076	37,876	33,802	27,500	25,586	331,801
263	Usage per Customer		4,760	4,186	3,735	3,039	2,828	36,667
264								
265	LTG & PWR-SEC NET-METERING	292						
266	Customer bills		4	4	4	4	4	48
267	Demand		990	919	894	864	860	11,232
268	Usage		441,438	441,080	316,153	253,127	342,809	4,285,757
269	Usage per Customer		109,763	109,674	78,611	62,939	85,239	1,065,645
270								
271	LLP PRIMARY W/ SBMAA	319						
272	Customer bills		1	1	1	1	1	12
273	Demand		17,137	16,502	-	30,706	30,552	195,256
274	Usage		8,407,721	7,873,892	5,716,853	4,681,505	5,325,654	80,209,798
275	Usage per Customer		8,362,256	7,831,314	5,685,939	4,656,190	5,296,856	79,776,063
276								
277	PULP & PAPER MILL SERVICE-DOMTAR	326						
278	Customer bills		1	1	1	1	1	12
279	Demand		47,723	37,829	38,084	37,829	38,020	466,021
280	Usage		24,376,705	23,353,293	20,176,636	17,489,180	17,275,757	243,588,954
281	Usage per Customer		24,417,606	23,392,476	20,210,489	17,518,524	17,304,743	243,997,661
282								
283	LTG&PWR-PRIMARY-CURTAILABLE DEMAND	336						
284	Customer bills		5	5	5	5	5	60
285	Demand		14,792	14,097	13,754	13,714	13,700	171,091
286	Usage		2,409,289	2,309,480	2,443,553	2,193,787	2,200,773	28,797,046
287	Usage per Customer		480,612	460,702	487,447	437,623	439,017	5,744,519
288								
289	LARGE LTG & POWER-YR 2-TRANS 69 KV	342						
290	Customer bills		1	1	1	1	1	12
291	Demand		22,503	22,854	22,331	21,434	21,542	262,644
292	Usage		14,241,983	13,518,816	13,932,958	14,178,613	11,199,694	156,167,361
293	Usage per Customer		14,265,878	13,541,499	13,956,335	14,202,403	11,218,485	156,429,387
294								
295	LARGE LTG & POWER-YEAR 2-PRIMARY	346						
296	Customer bills		1	1	1	1	1	12
297	Demand		13,583	13,752	12,936	11,568	11,627	149,513
298	Usage		8,616,122	9,000,828	7,679,864	7,342,385	7,502,832	94,294,653
299	Usage per Customer		8,630,579	9,015,930	7,692,749	7,354,705	7,515,421	94,452,866
300								

SOUTHWESTERN ELECTRIC POWER COMPANY
ARKANSAS JURISDICTIONAL
BILLING DETERMINANTS - PRO FORMA YEAR 2019

Line No.	Rate Schedule		Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19
301	MUNICIPAL STREET & PARKWAY LTG-YR 2	528							
302	Customer bills		4,818	4,818	4,818	4,818	4,818	4,818	4,818
303	Demand		-	-	-	-	-	-	-
304	Usage		376,439	376,450	376,450	376,450	376,934	376,716	376,866
305	Usage per Customer		78	78	78	78	78	78	78
306									
307	MUNICIPAL STREET LIGHTING-YEAR 2	529							
308	Customer bills		4,791	4,791	4,791	4,791	4,791	4,791	4,791
309	Demand		-	-	-	-	-	-	-
310	Usage		301,753	301,687	300,785	300,718	300,544	300,622	300,967
311	Usage per Customer		63	63	63	63	63	63	63
312									
313	MUNICIPAL STREET LTG-YR 2-VA HILLS	530							
314	Customer bills		39	39	39	39	39	39	39
315	Demand		-	-	-	-	-	-	-
316	Usage		1,638	1,638	1,638	1,638	1,638	1,638	1,638
317	Usage per Customer		42	42	42	42	42	42	42
318									
319	MUNICIPAL STREET & PARKWAY LTG	531							
320	Customer bills		4,288	4,288	4,288	4,288	4,288	4,288	4,288
321	Demand		-	-	-	-	-	-	-
322	Usage		263,113	262,672	263,438	262,912	262,922	262,418	261,857
323	Usage per Customer		61	61	61	61	61	61	61
324									
325	PUBLIC ST&HIWAY LTG-YR2-ENERGY ONLY	534							
326	Customer bills		123	123	123	123	123	123	123
327	Demand		-	-	-	-	-	-	-
328	Usage		6,970	6,970	6,970	6,970	6,970	6,970	6,970
329	Usage per Customer		57	57	57	57	57	57	57
330									
331	PUBLIC ST & HIGHWAY LTG - YEAR 2	535							
332	Customer bills		54	54	54	54	54	54	54
333	Demand		-	-	-	-	-	-	-
334	Usage		4,493	4,493	4,493	4,493	4,493	4,493	4,493
335	Usage per Customer		83	83	83	83	83	83	83
336									
337	PUBLIC ST & HIGHWAY LTG-ENERGY ONLY	536							
338	Customer bills		84	84	84	84	84	84	84
339	Demand		-	-	-	-	-	-	-
340	Usage		9,311	9,311	9,311	9,311	9,311	9,311	9,311
341	Usage per Customer		111	111	111	111	111	111	111
342									
343	PUBLIC ST & HIGHWAY LTG	537							
344	Customer bills		42	42	42	42	42	42	42
345	Demand		-	-	-	-	-	-	-
346	Usage		2,514	2,514	2,514	2,499	2,495	2,495	2,495
347	Usage per Customer		60	60	60	60	59	59	59
348									
349	MUNI PUMPING-YR2-SECONDARY	540							
350	Customer bills		63	63	63	63	63	63	63
351	Demand		2,446	2,421	2,449	2,488	2,488	2,489	2,489
352	Usage		380,598	345,729	357,725	340,012	276,641	273,082	250,991
353	Usage per Customer		6,009	5,458	5,647	5,368	4,367	4,311	3,962
354									
355	MUNI SERVICE-YEAR 2-SECONDARY	544							
356	Customer bills		483	483	483	483	483	483	483
357	Demand		2,704	2,690	2,674	2,653	2,614	2,613	2,605
358	Usage		602,860	500,005	435,528	395,734	378,308	475,338	536,989
359	Usage per Customer		1,249	1,036	902	820	784	985	1,113
360									
361	MUNI PUMPING-SEC-CONJUNCTIVE	549							
362	Customer bills		-	-	-	-	-	-	-
363	Demand		-	-	-	-	-	-	-
364	Usage		-	-	-	-	-	-	-
365	Usage per Customer		-	-	-	-	-	-	-
366									
367	MUNI PUMPING-YR2-SEC-NONCONJUNCTIVE	550							
368	Customer bills		208	208	208	208	208	208	208
369	Demand		3,952	3,960	3,868	3,866	3,953	4,178	3,820
370	Usage		1,044,263	982,678	1,000,740	849,751	855,491	1,032,377	854,153
371	Usage per Customer		5,017	4,722	4,808	4,083	4,110	4,960	4,104
372									
373	ARKANSAS TOTALS								
374	Customer bills		150,754	150,754	150,754	150,754	150,754	150,754	150,754
375	Demand		528,360	528,898	531,266	532,147	571,970	589,858	599,691
376	Usage		329,062,779	309,894,043	293,287,979	279,102,611	273,649,242	336,910,161	374,562,474
377	Usage per Customer		2,183	2,056	1,945	1,851	1,815	2,235	2,485

Supporting Schedules
WP G-3

Line No.	Rate Schedule		Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	12 Month Total
301	MUNICIPAL STREET & PARKWAY LTG-YR 2	528						
302	Customer bills		4,818	4,818	4,818	4,818	4,818	57,816
303	Demand		-	-	-	-	-	-
304	Usage		377,378	377,395	377,485	377,697	377,685	4,523,947
305	Usage per Customer		78	78	78	78	78	939
306								
307	MUNICIPAL STREET LIGHTING-YEAR 2	529						
308	Customer bills		4,791	4,791	4,791	4,791	4,791	57,492
309	Demand		-	-	-	-	-	-
310	Usage		301,080	301,227	315,152	314,812	313,393	3,652,740
311	Usage per Customer		63	63	66	66	65	762
312								
313	MUNICIPAL STREET LTG-YR 2-VA HILLS	530						
314	Customer bills		39	39	39	39	39	468
315	Demand		-	-	-	-	-	-
316	Usage		1,641	1,641	1,637	1,638	1,638	19,660
317	Usage per Customer		42	42	42	42	42	504
318								
319	MUNICIPAL STREET & PARKWAY LTG	531						
320	Customer bills		4,288	4,288	4,288	4,288	4,288	51,456
321	Demand		-	-	-	-	-	-
322	Usage		262,386	262,483	248,056	248,268	249,693	3,110,217
323	Usage per Customer		61	61	58	58	58	725
324								
325	PUBLIC ST&HIWAY LTG-YR2-ENERGY ONLY	534						
326	Customer bills		123	123	123	123	123	1,476
327	Demand		-	-	-	-	-	-
328	Usage		6,982	6,982	6,965	6,968	6,970	83,657
329	Usage per Customer		57	57	57	57	57	680
330								
331	PUBLIC ST & HIGHWAY LTG - YEAR 2	535						
332	Customer bills		54	54	54	54	54	648
333	Demand		-	-	-	-	-	-
334	Usage		4,501	4,501	4,490	4,492	4,493	53,927
335	Usage per Customer		83	83	83	83	83	999
336								
337	PUBLIC ST & HIGHWAY LTG-ENERGY ONLY	536						
338	Customer bills		84	84	84	84	84	1,008
339	Demand		-	-	-	-	-	-
340	Usage		9,327	9,327	9,304	9,309	9,311	111,755
341	Usage per Customer		111	111	111	111	111	1,330
342								
343	PUBLIC ST & HIGHWAY LTG	537						
344	Customer bills		42	42	42	42	42	504
345	Demand		-	-	-	-	-	-
346	Usage		2,499	2,499	2,525	2,513	2,514	30,077
347	Usage per Customer		60	60	60	60	60	716
348								
349	MUNI PUMPING-YR2-SECONDARY	540						
350	Customer bills		63	63	63	63	63	760
351	Demand		553	552	576	543	549	20,042
352	Usage		276,592	281,539	241,140	241,554	269,560	3,535,164
353	Usage per Customer		4,367	4,445	3,807	3,813	4,256	55,810
354								
355	MUNI SERVICE-YEAR 2-SECONDARY	544						
356	Customer bills		483	483	483	483	483	5,791
357	Demand		2,614	2,601	2,553	2,572	2,559	31,451
358	Usage		555,324	525,344	422,137	400,585	484,946	5,713,097
359	Usage per Customer		1,151	1,089	875	830	1,005	11,838
360								
361	MUNI PUMPING-SEC-CONJUNCTIVE	549						
362	Customer bills		-	-	-	-	-	-
363	Demand		-	-	756	1,199	1,199	3,155
364	Usage		-	-	-	-	-	-
365	Usage per Customer		-	-	-	-	-	-
366								
367	MUNI PUMPING-YR2-SEC-NONCONJUNCTIVE	550						
368	Customer bills		208	208	208	208	208	2,498
369	Demand		4,545	4,276	4,334	4,368	4,346	49,464
370	Usage		1,350,533	1,167,302	943,534	950,446	1,073,956	12,105,225
371	Usage per Customer		6,489	5,609	4,533	4,567	5,160	58,163
372								
373	ARKANSAS TOTALS							
374	Customer bills		150,754	150,754	150,754	150,754	150,754	1,809,048
375	Demand		619,208	602,804	582,337	560,330	563,955	6,810,824
376	Usage		392,384,071	378,404,817	314,517,950	278,482,404	306,863,707	3,867,122,238
377	Usage per Customer		2,603	2,510	2,086	1,847	2,036	25,652

Supporting Schedules
WP G-3

Southerwestern Electric Power Company
Other Operating Statistics
Test Year Ending December 31, 2018
Docket No. 19-008-U

SCHEDULE E-13

Explanation: Schedule showing miscellaneous operating statistics and an analysis of a typical billing cycle.

I. Schedule for each of the five years immediately prior to the test year for:
(a) Overtime hours and, if available, whether classified as expense or capitalized.
(b) Ratio of Capitalized/expensed payroll including dollar amounts.

Line No.	Description	Test Year		2017		2016		2015		2014		2013	
	SWEPCO												
1	Overtime hours in $	19,769,187		18,844,199		16,330,107		17,898,811		16,429,686		16,947,620	
2	Capitalized	6,995,305	35.38%	3,894,529	20.67%	3,698,409	22.65%	4,288,503	23.96%	2,647,264	16.11%	3,112,027	18.36%
3	Expenses	12,755,308	64.52%	13,614,997	72.25%	11,991,791	73.43%	13,610,308	76.04%	13,782,423	83.89%	13,835,593	81.64%
4	Other	18,574	0.09%	1,334,672	7.08%	639,907	3.92%						
5													
6	Total Payroll in $	143,275,769		139,474,329		141,992,974		138,789,418		134,931,149		126,918,369	
7	Capitalized/Other	41,064,272	28.66%	36,788,418	26.38%	40,483,393	28.51%	41,389,506	29.81%	41,104,555	30.46%	37,911,506	29.87%
8	Expensed	101,940,500	71.15%	100,410,616	71.99%	100,239,492	70.59%	96,892,231	69.81%	93,391,055	69.21%	88,158,901	69.46%
9	Other	270,998	0.19%	2,275,295	12.07%	1,270,089	0.89%	507,681	0.37%	435,539	0.32%	847,962	0.67%
10	AEPSC												
11	Overtime hours in $	2,479,469		2,137,677		2,205,935		2,540,673		2,359,280		2,205,935	
12	Capitalized	729,575	29.42%	640,329	29.95%	886,408	40.18%	1,195,546	47.06%	927,136	39.30%	886,408	40.18%
13	Expenses	1,607,486	64.83%	1,372,217	64.19%	1,230,512	55.78%	1,230,464	48.43%	1,327,255	56.26%	1,230,512	55.78%
14	Other	142,408	5.74%	125,131	5.85%	89,016	4.04%	114,662	4.51%	104,889	4.45%	89,016	4.04%
15													
16	Total Payroll in $	80,806,454		74,300,424		80,886,344		78,344,271		80,408,356		69,604,051	
17	Capitalized/Other	24,877,005	30.79%	21,370,005	28.76%	24,808,483	30.67%	25,845,012	32.99%	26,580,997	33.06%	22,611,536	32.49%
18	Expensed	49,813,874	61.65%	47,435,394	63.84%	50,551,648	62.50%	47,191,361	60.24%	49,431,378	61.48%	43,205,744	62.07%
19	Other	6,115,574	7.57%	5,495,024	7.40%	5,526,213	6.83%	5,307,898	6.78%	4,395,981	5.47%	3,786,771	5.44%

Supporting Schedules and Workpapers:

Recap Schedules

Schedule E-14

Southerwestern Electric Power Company
Calculatioin of AFUDC
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Description of the company's method for calculating Allowance for Funds Used During Construction and determination of the rate used in the test year.

I. Provide a detailed narrative of how AFUDC is calculated, compounded and recorded. Include an example of the actual formula used to calculate AFUDC.

Line No.	Description
1	See Attached
II.	Provide the AFUDC rates used during the test year (both debt and equity components) and explain how the formula in Part I was used to derive those rates.
2	The AFUDC rates used during the test year are provided in the calculations in w/p E-14-1 through July 2018.
3	The Arkansas ROE rate from Docket 09-008-U is 10.25%. The blended rate used in the calculations provide on w/p E-14-1 is 9.82%. The company includes an adjustment for the AFUDC jurisdictional difference in WP B-2-2 and WP B-2-3-3.

Supporting Schedules and Workpapers:
WP E-14-1

Recap Schedules:

Policy/Procedure Title	Accounting for Allowance for Funds Used During Construction and Capitalized Interest	**Date**	7/29/13

Purpose

This accounting policy / procedure memo serves to update and replace AEP Accounting Bulletin 1, "Accounting for Allowance for Funds Used During Construction." This document outlines AEP's procedures for computing and capitalizing allowance for funds used during construction and capitalized interest. Additionally, the underlying principles governing the accounting for this construction cost factor are presented.

This policy / procedure document may not be released to parties outside AEP without the approval of the Chief Accounting Officer.

Policy/Procedure Statement

I. Summary of Principles Permitting Allowance for Funds Used During Construction (AFUDC) and Capitalized Interest

A. FERC Uniform System of Accounts

Effective January 1, 1977, the FERC ordered new accounting procedures for AFUDC (Order No. 561 issued February 2, 1977).

AFUDC as provided in the Uniform System of Accounts is a two-part allowance. It includes:

1. An allowance for other funds used during construction, which includes the cost of common equity and preferred stock when so used, and;

2. An allowance for borrowed funds used during construction, which includes the cost of short-term debt and long-term debt when so used.

AFUDC is capitalized on the company's books by charging Account 107, Construction Work in Progress, as a component of construction cost and crediting Other Income, Account 419.1 – Allowance for Other Funds Used During Construction and/or crediting Interest Charges, Account 432 – Allowance for Borrowed Funds Used During Construction – Credit, as appropriate.

B. Generally Accepted Accounting Principles

Capitalization of Interest

Accounting Standards Codification (ASC) 835-20, Capitalization of Interest, permits capitalization of interest by all entities; however, such costs are limited to actual interest expense incurred for borrowed funds, imputed interest on certain payables and interest related to capital leases. AEP applies capitalized interest to its non-regulated subsidiaries in accordance with ASC 835-20.

The capitalization period begins when expenditures for the asset have been made, activities necessary to get the asset ready for its intended use are in progress, and interest cost is being incurred. Interest capitalization continues as long as those three conditions are present. If substantially all activities related to the construction of the asset are suspended, interest capitalization should cease until activities are resumed.

The amount capitalized in an accounting period is determined by applying the capitalization rate to the average amount of accumulated expenditures for the asset during the period. The capitalization rates are the prior month's weighted average debt cost for the applicable AEP subsidiary. The total amount of interest cost capitalized in an accounting period should not exceed the total amount of interest cost incurred in that period.

The capitalization period ends when the asset is substantially complete and ready for its intended use.

ASC 835-20 recognizes that regulated entities capitalize both a cost of debt and a cost of equity capital during the construction period in accordance with ASC 980-835.

AFUDC

ASC 980-835, Regulated Operations, Interest, addresses cases where a regulator requires an entity to capitalize the cost of financing construction as financed partially by borrowings and partially by equity (AFUDC). In such cases, the amounts capitalized for rate-making purposes as part of the cost of acquiring the assets shall be capitalized for financial reporting purposes instead of the amount of interest that would be capitalized in accordance with ASC 835-20.

AEP applies AFUDC to its regulated subsidiaries in accordance with ASC 980-835. The prior month's weighted average debt cost and equity cost for the applicable AEP subsidiary are used to determine the AFUDC rate.

With the exception of the rate calculation, procedures to apply capital interest are the same as used for AFUDC unless indicated.

II. Rate for Computing AFUDC

A. Authorization of Rate for Computing AFUDC

The FERC has granted permission to utilities to calculate the AFUDC rate on a monthly basis instead of annually as specified in Electric Plant Instruction No. 3, Item 17. This change enables a utility to calculate AFUDC using the maximum allowed rate on a monthly basis and avoids the need for a retroactive adjustment of AFUDC to the maximum allowed rate.

AEP uses the monthly methodology for calculating AFUDC rates. The balances for long-term debt, preferred stock, common stock and construction work in progress are the actual book balances at the end of the prior month. The interest rate for long-term debt and the cost rate for preferred stock are based on the prior month's costs. The cost rate for common stock is the rate of return granted common equity in the last approved rate proceeding. The balance for short-term debt is the average daily balance for the prior month and the related interest rate is the average rate for the prior month.

B. Formula and Elements for Computing the Monthly Maximum Allowable Rate

Separate monthly rates for each company are developed using the formula and elements for the computation of AFUDC as contained in Electric Plant Instruction No. 3, Item 17, of the Uniform System of Accounts adjusted for the requirements of FERC Accounting Release AR-13 effective May 1, 1983. The formula and elements are as follows:

$$Ai = s\left(\frac{S}{W}\right) + d\left(\frac{D}{D+P+C}\right)\left(1 - \frac{S}{W}\right)$$

$$Ae = \left[1 - \frac{S}{W}\right]\left[p\left(\frac{P}{D+P+C}\right) + c\left(\frac{C}{D+P+C}\right)\right]$$

Ai = Gross allowance for borrowed funds used during construction rate
Ae = Allowance for other funds used during construction rate
S = Average short-term debt
s = Short-term debt interest rate
D = Long-term debt (including use-restricted debt)
d = Long-term debt interest rate (including rate of use-restricted debt)
P = Preferred stock
p = Preferred stock cost rate
C = Common equity
c = Common equity cost rate
W = Average balance in construction work in progress plus nuclear fuel in process of refinement, conversion, enrichment and fabrication, less asset retirement costs related to plant under construction

The rate for computing AFUDC as outlined above represents a maximum monthly, simple interest rate which cannot be exceeded without prior Commission approval.

C. <u>Compounding of AFUDC</u>
In Order No. 561, FERC noted that compounding of AFUDC would be permitted, but no more frequently than semiannually.

AEP uses a compounded rate for AFUDC based on semiannual compounding. The rate is developed and applied to construction on a monthly basis.

III. <u>Charges Exempt from Application of AFUDC</u>

AFUDC is to be applied on all construction expenditures with the following exceptions:

1. Meter and transformer blanket work orders.

2. Electric plant purchased.

3. Most work orders with a general plant work order type (general plant work orders mapped to account 397, communication equipment, have AFUDC applied to construction expenditures).

4. Work orders for acquiring land and land rights where new facilities are not being constructed on the land. See Item VI, below.

5. Any portion of construction work in progress which should be excluded from the application of AFUDC as a consequence of compensatory rate relief.

6. Ongoing landfill preparation activities where work may be done intermittently over several years.

7. Certain charge types such as unvouchered liabilities and billing credits.

IV. Method for Accruing AFUDC

AFUDC is to be computed by applying the applicable monthly rate to the previous month's closing balance in the work order (including AFUDC), plus one-half ($^1/_2$) of the current month's additions, less any unpaid retained percentages under contracts and any unpaid invoices included therein.

The computed base multiplied by the applicable monthly rate equals the AFUDC for the current month that is to be charged to the work order.

V. Period for Capitalization of AFUDC

A. Commencement

1. FERC Interpretation
FERC Accounting Release AR-5 (Revised) effective February 20, 1968 states that; "Interest during construction may be capitalized starting from the date that construction costs are continuously incurred on a planned progressive basis." Release AR-5 also states that; "No interest should be accrued during the period of interrupted construction unless the company can justify the interruption as being reasonable under the circumstances."

2. AEP System Implementation
AFUDC is to be capitalized, in accordance with the instructions contained in this policy / procedure memo, commencing with the month of the first charges to an eligible work order.

In the case of interrupted construction a project must meet the criteria specified in the AEP Work Order Suspension Policy to be considered eligible for suspension. Suspended work orders cease accruing AFUDC from the month the work order is suspended until the month the work order is reopened.

The accrual of AFUDC will automatically cease if a work order has no direct charges (labor, material, outside services, etc.) for a period exceeding 6 months.

B. Cessation

1. FERC Interpretation
FERC Accounting Release AR-5 (Revised) states that; "Capitalization of interest stops when the facilities have been tested and are placed in or ready for service. This would include those portions of construction projects completed and put into service although the project is not fully completed."

2. AEP System Implementation
The cessation of AFUDC is dependent upon the month of the in-service date of the facilities as reported in accordance with AEP's In Service Procedure.

The in-service date shall correspond to the first commitment to permanent use of the facilities in the performance of their intended functions (e.g., when electrical equipment is energized and permanently connection to the system). Temporary or limited operations for testing or for construction purposes are not construed as in-service.

A half-month of AFUDC will be calculated in the in-service month. If an in-service date is reported after the fact, any AFUDC calculated after the in-service month will be automatically reversed in the current month.

VI. AFUDC Applied to Land and Land Rights

The accrual of AFUDC on expenditures for land and land rights shall begin at the commencement of the related construction project.

AFUDC on land and land rights is part of the cost of constructing a new facility, and as such, these costs should be capitalized as part of the construction cost of the facility to be recovered through depreciation rather than as part of the cost of the land which is not depreciated. Accordingly AFUDC accrued on the cost of land and land rights shall be transferred to the related construction project as part of the cost of the facility constructed. This transfer will be made when the facility being constructed is placed in-service.

Southerwestern Electric Power Company
Calculation of AFUDC
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP E-14

SWEPCo
Computation Of AFUDC Rate
At January 31, 2018

Line No.	Description	Amount	
1	**AFUDC Rate - Simple (AFUDC_S)**		
2	Gross Rate for Borrowed Funds Ai=s(S/W)+d(D/D+P+C)(1-S/W)	2.16%	
3	Gross Rate for Other Funds Ae=[1-S/W][p(P/D+P+C)+c(C/D+P+C)]	2.95%	
4	Total AFUDC Simple Rate, AFUDC_S	5.10%	
5	**AFUDC Rate - Compound (Semi-Annual), Maximum Rate (AFUDC_C)**		Monthly
6	Gross Rate for Borrowed Funds - Maximum Rate Ai_C = (Ai/2)+((1+Ai/2)*Ai/2	2.17%	0.00178851
7	Gross Rate for Other Funds - Maximum Rate Ae_C = (Ae/2)+((1+Ae/2)*Ae/2)	2.97%	0.00244149
8	Total AFUDC Maximum Rate, AFUDC_C = Ai_C + Ae_C	5.14%	
9	AFUDC_C=((1*AFUDC_S)/2)+((1+(AFUDC_S/2))*(AFUDC_S/2))		
10	Ai=Gross allowance for borrowed funds used during construction rate.		
11	Ae=Allowance for other funds used during construction rate.		
12	S=Prior month average short-term debt balance. ($000)	83,629,163	
13	s=Short term debt interest rate.	1.67160000%	
14	D=Prior month ending Long-term debt balance. ($000)	2,355,897,532	
15	d=Long-term debt interest rate.	4.74320000%	
16	P=Prior month ending Preferred stock balance. ($000)	0	
17	p=Preferred stock cost rate.	0.00000000%	
18	C=Prior month ending Common Equity balance. ($000)	2,203,025,532	
19	c=Common equity cost rate.	9.82000000%	
20	W=Average balance in construction work in progress. ($000)	220,763,745	
21	S/W=	37.88%	
22	1-S/W=	62.12%	
23	D+P+C= Total capitalization. ($000)	4,558,923,064	

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Calculation of AFUDC
Test Year Ending December 31, 2018
Docket No. 19-008-U

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SWEPCo
Computation Of AFUDC Rate
At February 28, 2018

Line No.	Description	Amount	
1	**AFUDC Rate - Simple (AFUDC_S)**		
2	Gross Rate for Borrowed Funds Ai=s(S/W)+d(D/D+P+C)(1-S/W)	2.34%	
3	Gross Rate for Other Funds Ae=[1-S/W][p(P/D+P+C)+c(C/D+P+C)]	4.33%	
4	Total AFUDC Simple Rate, AFUDC_S	6.67%	
5	**AFUDC Rate - Compound (Semi-Annual), Maximum Rate (AFUDC_C)**		Monthly
6	Gross Rate for Borrowed Funds - Maximum Rate Ai_C = (Ai/2)+((1+Ai/2)*Ai/2	2.35%	0.00193823
7	Gross Rate for Other Funds - Maximum Rate Ae_C = (Ae/2)+((1+Ae/2)*Ae/2)	4.38%	0.00357475
8	Total AFUDC Maximum Rate, AFUDC_C = Ai_C + Ae_C	6.73%	
9	AFUDC_C=((1*AFUDC_S)/2)+((1+(AFUDC_S/2))*(AFUDC_S/2))		
10	Ai=Gross allowance for borrowed funds used during construction rate.		
11	Ae=Allowance for other funds used during construction rate.		
12	S=Prior month average short-term debt balance. ($000)	460,554	
13	s=Short term debt interest rate.	1.89480000%	
14	D=Prior month ending Long-term debt balance. ($000)	2,800,891,910	
15	d=Long-term debt interest rate.	4.18699700%	
16	P=Prior month ending Preferred stock balance. ($000)	0	
17	p=Preferred stock cost rate.	0.00000000%	
18	C=Prior month ending Common Equity balance. ($000)	2,215,017,667	
19	c=Common equity cost rate.	9.82000000%	
20	W=Average balance in construction work in progress. ($000)	241,332,979	
21	S/W=	0.19%	
22	1-S/W=	99.81%	
23	D+P+C= Total capitalization. ($000)	5,015,909,576	

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SWEPCo
Computation Of AFUDC Rate
At March 31, 2018

Line No.	Description	Amount	
1	**AFUDC Rate - Simple (AFUDC_S)**		
2	Gross Rate for Borrowed Funds Ai=s(S/W)+d(D/D+P+C)(1-S/W)	2.58%	
3	Gross Rate for Other Funds Ae=[1-S/W][p(P/D+P+C)+c(C/D+P+C)]	4.31%	
4	Total AFUDC Simple Rate, AFUDC_S	6.90%	
5	**AFUDC Rate - Compound (Semi-Annual), Maximum Rate (AFUDC_C)**		Monthly
6	Gross Rate for Borrowed Funds - Maximum Rate Ai_C = (Ai/2)+((1+Ai/2)*Ai/2	2.60%	0.00214099
7	Gross Rate for Other Funds - Maximum Rate Ae_C = (Ae/2)+((1+Ae/2)*Ae/2)	4.36%	0.00356388
8	Total AFUDC Maximum Rate, AFUDC_C = Ai_C + Ae_C	6.96%	
9	AFUDC_C=((1*AFUDC_S)/2)+((1+(AFUDC_S/2))*(AFUDC_S/2))		
10	Ai=Gross allowance for borrowed funds used during construction rate.		
11	Ae=Allowance for other funds used during construction rate.		
12	S=Prior month average short-term debt balance. ($000)	0	
13	s=Short term debt interest rate.	0.00000000%	
14	D=Prior month ending Long-term debt balance. ($000)	2,801,145,340	
15	d=Long-term debt interest rate.	4.60755900%	
16	P=Prior month ending Preferred stock balance. ($000)	0	
17	p=Preferred stock cost rate.	0.00000000%	
18	C=Prior month ending Common Equity balance. ($000)	2,195,577,395	
19	c=Common equity cost rate.	9.82000000%	
20	W=Average balance in construction work in progress. ($000)	265,995,479	
21	S/W=	0.00%	
22	1-S/W=	100.00%	
23	D+P+C= Total capitalization. ($000)	4,996,722,735	

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SWEPCo
Computation Of AFUDC Rate
At April 30, 2018

Line No.	Description	Amount	
1	**AFUDC Rate - Simple (AFUDC_S)**		
2	Gross Rate for Borrowed Funds Ai=s(S/W)+d(D/D+P+C)(1-S/W)	2.28%	
3	Gross Rate for Other Funds Ae=[1-S/W][p(P/D+P+C)+c(C/D+P+C)]	1.96%	
4	Total AFUDC Simple Rate, AFUDC_S	4.24%	
5	**AFUDC Rate - Compound (Semi-Annual), Maximum Rate (AFUDC_C)**		Monthly
6	Gross Rate for Borrowed Funds - Maximum Rate Ai_C = (Ai/2)+((1+Ai/2)*Ai/2	2.29%	0.00189100
7	Gross Rate for Other Funds - Maximum Rate Ae_C = (Ae/2)+((1+Ae/2)*Ae/2)	1.97%	0.00162630
8	Total AFUDC Maximum Rate, AFUDC_C = Ai_C + Ae_C	4.26%	
9	AFUDC_C=((1*AFUDC_S)/2)+((1+(AFUDC_S/2))*(AFUDC_S/2))		
10	Ai=Gross allowance for borrowed funds used during construction rate.		
11	Ae=Allowance for other funds used during construction rate.		
12	S=Prior month average short-term debt balance. ($000)	150,093,298	
13	s=Short term debt interest rate.	2.22730000%	
14	D=Prior month ending Long-term debt balance. ($000)	2,419,535,681	
15	d=Long-term debt interest rate.	4.48237300%	
16	P=Prior month ending Preferred stock balance. ($000)	0	
17	p=Preferred stock cost rate.	0.00000000%	
18	C=Prior month ending Common Equity balance. ($000)	2,190,205,438	
19	c=Common equity cost rate.	9.82000000%	
20	W=Average balance in construction work in progress. ($000)	258,772,095	
21	S/W=	58.00%	
22	1-S/W=	42.00%	
23	D+P+C= Total capitalization. ($000)	4,609,741,119	

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SWEPCo
Computation Of AFUDC Rate
At May 31, 2018

Line No.	Description	Amount	
1	**AFUDC Rate - Simple (AFUDC_S)**		
2	Gross Rate for Borrowed Funds Ai=s(S/W)+d(D/D+P+C)(1-S/W)	2.43%	
3	Gross Rate for Other Funds Ae=[1-S/W][p(P/D+P+C)+c(C/D+P+C)]	1.84%	
4	Total AFUDC Simple Rate, AFUDC_S	4.27%	
5	**AFUDC Rate - Compound (Semi-Annual), Maximum Rate (AFUDC_C)**		Monthly
6	Gross Rate for Borrowed Funds - Maximum Rate Ai_C = (Ai/2)+((1+Ai/2)*Ai/2	2.45%	0.00201651
7	Gross Rate for Other Funds - Maximum Rate Ae_C = (Ae/2)+((1+Ae/2)*Ae/2)	1.85%	0.00152721
8	Total AFUDC Maximum Rate, AFUDC_C = Ai_C + Ae_C	4.29%	
9	AFUDC_C=((1*AFUDC_S)/2)+((1+(AFUDC_S/2))*(AFUDC_S/2))		
10	Ai=Gross allowance for borrowed funds used during construction rate.		
11	Ae=Allowance for other funds used during construction rate.		
12	S=Prior month average short-term debt balance. ($000)	173,095,785	
13	s=Short term debt interest rate.	2.49130000%	
14	D=Prior month ending Long-term debt balance. ($000)	2,419,706,226	
15	d=Long-term debt interest rate.	4.46268500%	
16	P=Prior month ending Preferred stock balance. ($000)	0	
17	p=Preferred stock cost rate.	0.00000000%	
18	C=Prior month ending Common Equity balance. ($000)	2,193,205,192	
19	c=Common equity cost rate.	9.82000000%	
20	W=Average balance in construction work in progress. ($000)	285,647,890	
21	S/W=	60.60%	
22	1-S/W=	39.40%	
23	D+P+C= Total capitalization. ($000)	4,612,911,418	

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Calculation of AFUDC
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SWEPCo
Computation Of AFUDC Rate
At June 30, 2018

Line No.	Description	Amount	
1	**AFUDC Rate - Simple (AFUDC_S)**		
2	Gross Rate for Borrowed Funds Ai=s(S/W)+d(D/D+P+C)(1-S/W)	2.45%	
3	Gross Rate for Other Funds Ae=[1-S/W][p(P/D+P+C)+c(C/D+P+C)]	0.83%	
4	Total AFUDC Simple Rate, AFUDC_S	3.28%	
5	**AFUDC Rate - Compound (Semi-Annual), Maximum Rate (AFUDC_C)**		Monthly
6	Gross Rate for Borrowed Funds - Maximum Rate Ai_C = (Ai/2)+((1+Ai/2)*Ai/2	2.47%	0.00203200
7	Gross Rate for Other Funds - Maximum Rate Ae_C = (Ae/2)+((1+Ae/2)*Ae/2)	0.83%	0.00069011
8	Total AFUDC Maximum Rate, AFUDC_C = Ai_C + Ae_C	3.30%	
9	AFUDC_C=((1*AFUDC_S)/2)+((1+(AFUDC_S/2))*(AFUDC_S/2))		
10	Ai=Gross allowance for borrowed funds used during construction rate.		
11	Ae=Allowance for other funds used during construction rate.		
12	S=Prior month average short-term debt balance. ($000)	186,755,057	
13	s=Short term debt interest rate.	2.47450000%	
14	D=Prior month ending Long-term debt balance. ($000)	2,419,645,280	
15	d=Long-term debt interest rate.	4.46914800%	
16	P=Prior month ending Preferred stock balance. ($000)	0	
17	p=Preferred stock cost rate.	0.00000000%	
18	C=Prior month ending Common Equity balance. ($000)	2,199,544,345	
19	c=Common equity cost rate.	9.82000000%	
20	W=Average balance in construction work in progress. ($000)	227,032,125	
21	S/W=	82.26%	
22	1-S/W=	17.74%	
23	D+P+C= Total capitalization. ($000)	4,619,189,626	

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Calculation of AFUDC
Test Year Ending December 31, 2018
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SWEPCo
Computation Of AFUDC Rate
At July 31, 2018

Line No.	Description	Amount	
1	**AFUDC Rate - Simple (AFUDC_S)**		
2	Gross Rate for Borrowed Funds Ai=s(S/W)+d(D/D+P+C)(1-S/W)	2.38%	
3	Gross Rate for Other Funds Ae=[1-S/W][p(P/D+P+C)+c(C/D+P+C)]	1.12%	
4	Total AFUDC Simple Rate, AFUDC_S	3.50%	
5	**AFUDC Rate - Compound (Semi-Annual), Maximum Rate (AFUDC_C)**		Monthly
6	Gross Rate for Borrowed Funds - Maximum Rate Ai_C = (Ai/2)+((1+Ai/2)*Ai/2	2.39%	0.00197163
7	Gross Rate for Other Funds - Maximum Rate Ae_C = (Ae/2)+((1+Ae/2)*Ae/2)	1.13%	0.00093357
8	Total AFUDC Maximum Rate, AFUDC_C = Ai_C + Ae_C	3.52%	
9	AFUDC_C=((1*AFUDC_S)/2)+((1+(AFUDC_S/2))*(AFUDC_S/2))		
10	Ai=Gross allowance for borrowed funds used during construction rate.		
11	Ae=Allowance for other funds used during construction rate.		
12	S=Prior month average short-term debt balance. ($000)	165,957,722	
13	s=Short term debt interest rate.	2.39160000%	
14	D=Prior month ending Long-term debt balance. ($000)	2,419,793,792	
15	d=Long-term debt interest rate.	4.46773000%	
16	P=Prior month ending Preferred stock balance. ($000)	0	
17	p=Preferred stock cost rate.	0.00000000%	
18	C=Prior month ending Common Equity balance. ($000)	2,213,572,781	
19	c=Common equity cost rate.	9.82000000%	
20	W=Average balance in construction work in progress. ($000)	218,179,141	
21	S/W=	76.06%	
22	1-S/W=	23.94%	
23	D+P+C= Total capitalization. ($000)	4,633,366,574	

Supporting Schedules and Workpapers:

Recap Schedules:

Southerwestern Electric Power Company
Trial Balance - Income Statement
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

FERC	FERC Title	Account	Description	YTD 12/31/2016	YTD 12/31/2017	1/31/2018	2/28/2018	3/31/2018	4/30/2018	5/31/2018	6/30/2018
4400	**Residential Sales**	4400001	Residential Sales-W/Space Htg	(86,202,128.19)	(88,099,687.48)	(10,858,356.83)	(7,996,061.76)	(6,521,069.43)	(6,211,590.01)	(10,766,975.13)	(11,379,724.64)
		4400002	Residential Sales-W/O Space Ht	(312,596,716.68)	(329,131,776.15)	(31,313,900.79)	(21,614,674.85)	(16,603,082.29)	(19,792,791.03)	(35,036,013.98)	(43,226,721.43)
		4400005	Residential Fuel Rev	(189,633,073.26)	(179,747,786.04)	(21,968,771.61)	(16,647,936.36)	(13,075,548.37)	(11,631,984.13)	(12,381,026.77)	(19,801,191.55)
		4400006	Residential O/U Fuel Rev	(828,409.10)	(2,330,688.70)	(2,598,094.93)	(95,131.17)	651,920.60	(66,596.32)	(1,427,918.50)	1,375,487.18
	4400 Total			**(589,260,327.22)**	**(599,309,938.37)**	**(66,739,124.16)**	**(46,353,804.14)**	**(35,547,779.49)**	**(37,702,961.49)**	**(59,611,934.38)**	**(73,032,150.44)**
4420	**Commercial & Industrial Sales**	4420001	Commercial Sales	(236,636,415.35)	(254,368,506.63)	(20,435,874.30)	(18,398,320.13)	(18,882,338.53)	(18,917,644.78)	(28,725,118.68)	(23,263,293.28)
		4420002	Industrial Sales (Excl Mines)	(158,988,398.22)	(177,181,152.45)	(12,793,693.75)	(13,909,851.86)	(14,701,515.53)	(14,923,776.20)	(20,639,781.05)	(15,274,369.13)
		4420006	Sales to Pub Auth - Schools	(7,483,314.71)	(7,726,990.26)	(443,680.84)	(474,561.51)	(501,402.04)	(563,049.69)	(1,040,418.28)	(865,310.00)
		4420007	Sales to Pub Auth - Ex Schools	(50,630,831.10)	(51,947,854.14)	(3,922,912.72)	(4,291,703.68)	(4,636,854.01)	(4,571,928.53)	(6,833,295.88)	(5,409,388.53)
		4420013	Commercial Fuel Rev	(184,870,036.23)	(178,470,592.26)	(15,642,943.26)	(13,648,505.80)	(13,732,334.50)	(13,480,597.48)	(14,002,804.63)	(17,863,090.19)
		4420014	Commercial O/U Fuel Rev	(1,069,183.25)	(3,110,363.25)	(2,085,025.43)	(100,012.25)	661,653.45	(108,184.92)	(1,902,885.91)	1,372,974.16
		4420016	Industrial Fuel Rev	(148,375,091.47)	(154,222,428.41)	(12,631,645.75)	(11,862,284.97)	(13,020,457.04)	(12,953,920.75)	(13,304,774.70)	(14,646,603.11)
		4420017	Industrial O/U Fuel Rev	(963,339.66)	(3,225,514.47)	(2,218,594.13)	(66,698.12)	875,404.92	(18,685.87)	(2,271,011.04)	1,579,060.81
	4420 Total			**(789,016,609.99)**	**(830,253,401.87)**	**(70,174,370.18)**	**(62,751,938.32)**	**(63,937,843.28)**	**(65,537,788.22)**	**(88,720,090.17)**	**(74,370,019.27)**
4440	**Public Street/Highway Lighting**	4440000	Public Street/Highway Lighting	(5,716,322.62)	(6,331,477.19)	(482,646.92)	(514,887.31)	(568,733.38)	(454,212.42)	(745,226.51)	(457,063.13)
		4440002	Public St & Hwy Light Fuel Rev	(2,481,725.62)	(2,475,657.94)	(208,066.80)	(197,665.86)	(221,541.79)	(213,688.27)	(205,049.03)	(208,767.25)
		4440003	Pb St & Hwy Light O/U Fuel Rev	1,792.02	(27,961.74)	(21,932.15)	(496.09)	9,151.34	188.06	(21,315.09)	14,708.66
	4440 Total			**(8,196,256.22)**	**(8,835,096.87)**	**(712,645.87)**	**(713,049.26)**	**(781,123.83)**	**(667,712.63)**	**(971,590.63)**	**(651,121.72)**
4470	**Sales for Resale**	4470001	Sales for Resale - Assoc Cos	226,876.14	161,037.70	45,803.25	50,967.48	20,900.22	34,794.33	(12,187.81)	(20,288.96)
		4470002	Sales for Resale - NonAssoc	(5,671,511.64)	(6,057,179.01)	(177,444.98)	(1,084,167.46)	225,823.32	423,083.85	234,315.82	(239,864.01)
		4470006	Sales for Resale-Bookout Sales	(551,873.88)	(1,540,076.27)	(133,842.01)	(232,964.34)	(116,646.86)	(80,896.09)	(174,529.58)	(192,396.88)
		4470010	Sales for Resale-Bookout Purch	476,739.35	1,153,363.41	114,051.69	132,965.16	87,228.77	70,822.86	142,063.76	155,774.98
		4470027	Whsal/Muni/Pb Ath Fuel Rev	(78,821,054.86)	(75,826,052.61)	(7,736,274.71)	(7,457,077.09)	(6,712,619.69)	(6,061,750.55)	(9,368,332.04)	(7,670,489.90)
		4470028	Sale/Resale - NA - Fuel Rev	(43,012,936.87)	(53,571,863.06)	(5,799,527.68)	(5,441,323.77)	(3,877,392.36)	(3,159,954.06)	(1,934,170.69)	(4,218,441.77)
		4470032	Capacity Revenue - Affiliated	(1,753,360.00)							
		4470033	Whsal/Muni/Pub Auth Base Rev	(113,125,340.09)	(106,579,601.34)	(8,627,485.24)	(4,314,322.03)	(7,240,530.20)	(9,972,216.01)	(7,733,883.06)	(5,811,433.14)
		4470035	Sls for Rsl - Fuel Rev - Assoc	(1,930,994.45)							
		4470036	Sales for Resale- Fuel - ERCOT	(363,079.84)	(303,745.03)	(23,854.31)	(46,306.02)	(20,010.18)	(8,731.62)	(0.14)	(81,594.75)
		4470074	Sale for Resale-Aff-Trnf Price	(0.00)		-	-	-	-	-	-
		4470081	Financial Spark Gas - Realized	19,659.53							
		4470082	Financial Electric Realized	(25,394.94)	(1,995.82)						
		4470131	Non-Trading Bookout Purch-OSS	50,268.11	138,597.70	18,509.49	(82,581.79)	64,979.75	(14,776.65)	(82,795.61)	94,536.50
		4470136	SPP Rev Neutrality Ded-Sales	(272,934.36)	(40,725.00)	(183,661.67)	(13,631.10)	13,718.79	3,797.61	(4,542.13)	(5,350.67)
		4470150	Transm. Rev.-Dedic. Whlsl/Muni	(3,951,057.24)	(3,849,340.50)	(307,514.46)	(307,514.46)	(307,514.46)	(533,395.73)	(533,395.73)	(533,395.73)
		4470175	OSS Sharing Reclass - Retail	(10,294,115.67)	(15,092,275.31)	(1,960,036.50)	(1,854,512.57)	(697,102.38)	(649,578.33)	(346,623.31)	(615,111.85)
		4470176	OSS Sharing Reclass-Reduction	10,294,115.67	15,092,275.31	1,960,036.50	1,854,512.57	697,102.38	649,578.33	346,623.31	615,111.85
		4470219	Merchant Fuel Revenue	(10,178,844.31)	(11,634,300.26)	(972,810.29)	(896,963.45)	(976,391.22)	(914,885.19)	(181,751.04)	(854,109.42)
		4470223	Merchant Sales Margin	(2,524,421.82)	(4,608,028.24)	(572,867.12)	(220,939.76)	(165,663.62)	(290,769.74)	(94,085.26)	(514,083.47)
		4470320	SPP Net Regulation OSS	(1,382,308.22)	(2,129,516.02)	(275,887.78)	(126,788.35)	(191,581.47)	(175,311.50)	(64,042.79)	(70,493.09)
		4470321	SPP Net Spinning Reserve OSS	(3,200,331.43)	(3,779,990.75)	(542,949.28)	(321,105.03)	(167,789.43)	(276,098.21)	(239,688.51)	(223,300.58)
		4470324	SPP Net Supp Reserve OSS	(36,944.53)	(19,397.04)	(1,501.39)	(72.55)	289.65	(1,316.66)	(470.48)	(12,008.23)
		4470326	SPP Net Marginal Losses OSS	(545,078.62)	(889,172.70)	(80,258.02)	(118,617.73)	(215,806.30)	(102,563.85)	(60,223.07)	(101,044.60)
		4470328	SPP Net Make Whole Payment OSS	65,575.40	183,025.20	31,259.26	27,107.36	3,625.78	(16,375.83)	(15,977.50)	(25,970.08)
		4470332	SPP Congestion Costs OSS	(1,891,091.21)	(5,981,893.55)	(982,757.15)	(230,862.40)	(561,094.97)	(619,237.47)	(169,052.87)	(130,217.75)
	4470 Total			**(268,399,439.78)**	**(275,176,853.19)**	**(26,209,012.40)**	**(20,684,197.33)**	**(20,136,474.48)**	**(21,695,780.51)**	**(20,292,748.73)**	**(20,454,171.55)**
4491	**Provision for Rate Refunds**	4491002	Prov Rate Refund-Nonaffiliated	3,959,806.24	12,814,556.00	1,957,712.00	(428,472.00)	764,620.00	920,049.00	803,478.00	13,324,491.12
		4491003	Prov Rate Refund - Retail	466,365.27	8,248,327.94	1,951,180.91	(1,485,341.91)	(465,838.89)			
		4491004	Prov Rate Refund - Affiliated	164,720.00							
		4491018	Prov Rate Refund - Tax Reform				8,333,091.06	2,687,621.74	3,110,043.36	3,547,196.33	6,569,710.54
		4491019	Prov Rate Refund-Exces Protect					3,507,507.82	1,169,169.27	1,169,169.27	1,169,169.28
	4491 Total			**4,590,891.51**	**21,062,883.94**	**3,908,892.91**	**6,419,277.15**	**6,493,910.67**	**5,199,261.63**	**5,519,843.60**	**21,063,370.94**
4500	**Forfeited Discounts**	4500000	Forfeited Discounts	(4,584,175.01)	(4,738,499.98)	(393,852.55)	(458,827.09)	(406,368.07)	(285,335.30)	(339,223.67)	(457,190.52)
	4500 Total			**(4,584,175.01)**	**(4,738,499.98)**	**(393,852.55)**	**(458,827.09)**	**(406,368.07)**	**(285,335.30)**	**(339,223.67)**	**(457,190.52)**
4510	**Misc Service Revenues**	4510001	Misc Service Rev - Nonaffil	(2,303,132.58)	(2,285,496.10)	(140,894.84)	(192,522.73)	(190,445.44)	(177,031.62)	(188,342.49)	(175,149.94)
	4510 Total			**(2,303,132.58)**	**(2,285,496.10)**	**(140,894.84)**	**(192,522.73)**	**(190,445.44)**	**(177,031.62)**	**(188,342.49)**	**(175,149.94)**
4540	**Rent From Electric Property**	4540001	Rent From Elect Property - Af	(1,580,518.80)	(1,870,332.60)	(121,259.94)	(121,259.94)	(121,259.94)	(121,259.94)	(121,259.94)	(121,259.94)

Southerwestern Electric Power Company
Trial Balance - Income Statement
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

FERC	FERC Title	Account	Description	YTD 12/31/2016	YTD 12/31/2017	1/31/2018	2/28/2018	3/31/2018	4/30/2018	5/31/2018	6/30/2018
		4540002	Rent From Elect Property-NAC	(2,918,210.63)	(3,018,759.23)	(257,954.31)	(250,116.17)	(250,636.53)	(293,512.94)	(254,620.66)	(246,106.55)
		4540004	Rent From Elect Prop-ABD-Nonaf	(42,673.40)	(38,531.64)	(2,507.49)	(2,507.49)	(7,507.49)	(2,507.49)	(2,507.49)	(2,507.49)
		4540005	Rent from Elec Prop-Pole Attch	(5,100,255.85)	(4,873,564.28)	(407,422.30)	(422,476.00)	(410,855.46)	(402,464.55)	(401,391.37)	(401,453.82)
	4540 Total			**(9,641,658.68)**	**(9,801,187.75)**	**(789,144.04)**	**(796,359.60)**	**(790,259.42)**	**(819,744.92)**	**(779,779.46)**	**(771,327.80)**
4560	**Other Electric Revenues**	4560010	Oth Elect Rev - Royalties	(315,395.31)	(425,552.68)	3,262.27	(16,652.40)	(37,308.54)	(107,084.66)	(11,453.65)	(77,116.19)
		4560012	Oth Elect Rev - Nonaffiliated	(1,786,476.12)	(1,768,628.53)	(222,393.52)	(121,375.89)	(139,805.07)	(168,027.33)	(155,414.42)	(188,169.82)
		4560013	Oth Elect Rev-Trans-Nonaffil	(903,673.74)	(923,552.60)			(235,226.48)			(231,182.40)
		4560015	Other Electric Revenues - ABD	(949,652.51)	(870,747.86)	(58,888.86)	(44,580.92)	(27,050.33)	(67,287.38)	(94,688.14)	(59,490.09)
		4560025	Plant Operations O/H Revenues	(2,808,137.12)	(3,300,323.17)	(349,745.12)	(431,295.86)	(302,814.35)	(89,130.57)	(69,620.40)	(120,550.12)
		4560041	Miscellaneous Revenue-NonAffil	(21.39)							
		4560043	Oth Elec Rv-Trn-Aff-Trnf Price			-	-	-	-	0.00	(0.00)
		4560102	Oth Elect Rev-Trans-ERCOT area	(5.78)							
	4560 Total			**(6,763,361.97)**	**(7,288,804.84)**	**(627,765.23)**	**(613,905.07)**	**(742,204.77)**	**(431,529.94)**	**(331,176.61)**	**(676,508.62)**
4561	**Other Electric Revenues**	4561008	SPP Non-Affil. Base Fundng Rev	(42,716,250.72)	(35,620,045.17)	(3,462,885.32)	(3,374,535.72)	(3,442,923.43)	(3,314,777.57)	(3,557,492.48)	(6,138,203.85)
		4561009	SPP Affil. Base Funding Cost	15,022,841.59	15,783,682.66	1,984,439.18	1,996,935.45	1,988,087.27	1,981,797.81	2,073,261.62	3,919,417.17
		4561010	SPP Affl. Base Funding Rev	(18,916,899.73)	(20,394,477.31)	(2,629,199.35)	(2,563,387.40)	(2,602,258.87)	(2,572,640.80)	(2,698,855.24)	(5,093,561.58)
		4561011	SPP Pt to Pt Trans Serv Rev	(6,019,427.52)	(7,558,621.73)	(713,913.70)	(553,851.21)	(628,623.27)	(655,540.38)	(1,020,054.75)	(838,300.95)
		4561012	SPP Direct Assignment	(1,336,644.78)	(1,201,972.62)	(104,616.82)	(104,616.77)	(104,616.80)	(104,616.77)	(104,616.76)	(104,616.78)
		4561013	SPP Affiliated NITS Revenue	(73,262,910.10)	(79,692,139.85)	(8,082,767.96)	(6,639,378.18)	(5,632,839.02)	(5,523,396.27)	(8,372,468.58)	(5,801,407.57)
		4561014	SPP Ancillary Services	(392,672.06)	(410,833.43)	(17,528.19)	(17,129.79)	(16,184.32)	(23,207.71)	(38,678.33)	(40,591.91)
		4561015	SPP Ancillary Schedule 1	(970,123.08)	(964,570.77)	(144,966.62)	(120,093.68)	(99,084.58)	(87,744.44)	(122,224.38)	(131,335.17)
		4561016	SPP Affiliated Trans NITS Cost	57,757,308.48	60,408,980.40	6,660,147.53	5,143,326.87	4,572,653.87	4,138,943.41	6,348,283.00	6,653,611.23
		4561017	Oth Elect Revenues - Ancillary	(840.00)	(840.00)	(70.00)	(70.00)	(70.00)	(70.00)	(70.00)	(70.00)
		4561019	Oth Elec Rev Trans Non Aff			-	-	-	-	-	-
		4561020	Oth Elec Rev-Trans-Aff-SPP			-	-	-	-	-	-
		4561021	SPP NITS	(22,045,651.05)	(25,105,484.33)	(3,174,851.13)	(2,530,080.65)	(1,955,004.79)	(1,715,369.61)	(2,582,505.51)	(657,822.62)
		4561038	SPP Pt to Pt Trans Affil Cost	(11,237.97)							
		4561039	SPP Pt to Pt Trans Affil Rev	13,188.89							
		4561040	Affil. SPPAncillary Sch.1 Cost	1,771,615.25	1,807,958.04	286,497.20	223,934.79	198,895.71	180,896.35	275,943.95	290,522.86
		4561041	Affil. SPPAncillary Sch. 1 Rev	(1,985,644.68)	(2,069,305.70)	(290,145.37)	(240,188.72)	(203,524.38)	(200,325.98)	(302,766.71)	(326,030.59)
		4561042	SPP Base Funding Contra								
		4561065	Provision RTO Rev-NonAff		3,928,833.62	-	-	-	-	-	-
	4561 Total			**(93,093,347.48)**	**(91,088,836.19)**	**(9,689,860.55)**	**(8,779,135.01)**	**(7,925,492.61)**	**(7,896,051.96)**	**(10,102,244.17)**	**(8,268,389.76)**
5000	**Oper Supervision & Engineering**	5000000	Oper Supervision & Engineering	16,802,332.23	17,040,795.46	1,649,660.10	1,366,790.34	1,766,998.26	1,619,811.28	1,522,726.51	1,486,948.18
		5000001	Oper Super & Eng-RATA-Affil	207,468.38	264,324.84	15,931.99	1,325.13	8,635.64	26,118.24	23,189.72	8,513.67
	5000 Total			**17,009,800.61**	**17,305,120.30**	**1,665,592.09**	**1,368,115.47**	**1,775,633.90**	**1,645,929.52**	**1,545,916.23**	**1,495,461.85**
5010	**Fuel**	5010000	Fuel	3,377,655.88	4,982,618.05	353,890.25	410,315.72	308,116.18	444,792.80	627,289.64	288,406.72
		5010001	Fuel Consumed	176,243,335.53	221,477,323.76	20,484,273.64	14,277,650.83	13,179,546.44	13,686,159.06	8,961,171.89	18,385,236.53
		5010003	Fuel - Procure Unload & Handle	10,707,782.33	10,608,216.74	1,087,951.34	617,985.69	685,637.45	619,372.74	580,930.28	1,089,941.93
		5010005	Fuel - Deferred			-	-	-	-	-	-
		5010012	Ash Sales Proceeds	(3,779,127.31)	(3,945,859.49)	(372,257.78)	(365,959.90)	(556,986.22)	(319,697.36)	(463,281.96)	(570,308.58)
		5010013	Fuel Survey Activity	(130,318.12)	(637,184.84)	159,262.18	159,323.50	160,339.46	(154,105.32)	(307,097.82)	(307,097.82)
		5010018	Lignite Consumed	218,941,774.41	158,349,130.53	19,547,642.99	19,956,264.20	12,017,527.79	3,366,013.89	14,962,830.77	19,945,532.05
		5010019	Fuel Oil Consumed	2,346,967.60	1,827,994.71	70,887.64	136,099.94	187,640.75	81,569.72	468,305.19	121,906.17
		5010020	Nat Gas Consumed Steam	26,019,637.86	20,714,366.48	4,074,825.65	1,446,985.83	1,311,729.98	1,664,281.30	3,215,878.75	3,688,611.21
		5010021	Transp Gas Consumed Steam	3,540,521.52	2,017,653.82	184,201.61	252,252.11	150,930.52	118,497.85	341,561.62	292,593.24
		5010034	Gas Transp Res Fees-Steam	174,100.57	32,157.00	80,680.00	(91,744.00)	(4,858.00)	147,501.00	(14,791.00)	94,973.00
		5010035	Gas Transp Res Fees - CC	6,247,664.30	6,230,506.00	532,731.00	474,399.00	529,170.00	512,100.00	544,183.00	497,087.00
		5010036	Nat Gas Consumed CC	61,997,962.76	62,686,658.88	8,878,360.57	5,288,037.74	5,320,625.59	4,068,905.13	5,830,469.12	6,449,884.54
		5010037	Transportation Gas CC	4,831,915.16	243,000.20	21,454.37	30,237.00	20,486.93	7,370.15	23,505.05	37,251.70
	5010 Total			**510,519,872.49**	**484,586,581.84**	**55,103,903.46**	**42,591,847.66**	**33,309,906.87**	**24,242,760.96**	**34,770,954.53**	**50,014,017.69**
5020	**Steam Expenses**	5020000	Steam Expenses	12,513,326.23	11,933,027.91	1,390,361.74	867,996.56	1,042,826.11	991,425.25	1,000,054.05	1,067,354.19
		5020001	Lime Expense	1,738,557.88	1,612,014.84	25,410.86	111,176.49	65,214.01	68,366.74	33,209.08	113,919.72
		5020002	Urea Expense	34,778.07	40,397.93					28,968.48	
		5020003	Trona Expense	5,368.00	260.35						
		5020004	Limestone Expense	2,812,328.99	2,893,023.50	196,705.59	340,874.92	338,302.01	132,436.16	336,023.20	455,354.90
		5020005	Polymer expense	3,505.99	5,634.60				1,267.81		
		5020006	Consumable Expense-Deferred	(1,007,666.54)	(803,944.91)	(90,363.90)	(81,729.72)	(77,063.64)	(15,790.23)	(127,866.07)	(100,980.21)

Southerwestern Electric Power Company
Trial Balance - Income Statement
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

FERC	FERC Title	Account	Description	YTD 12/31/2016	YTD 12/31/2017	1/31/2018	2/28/2018	3/31/2018	4/30/2018	5/31/2018	6/30/2018
		5020007	Lime Hydrate Expense	190,013.97	140,257.39	323.28	14,429.33	16,614.38	4,132.37	20,166.96	12,404.35
		5020008	Activated Carbon	5,283,803.13	4,050,014.02	470,693.64	400,935.35	275,003.82	124,999.72	650,072.19	498,769.34
		5020013	Anhydrous Ammonia Expense	758,914.30	866,132.76	109,357.17	74,746.56	80,614.92	96,194.79	15,957.82	91,029.96
		5020014	Calcium Bromide Expense	243,124.63	194,858.55	21,153.75	18,730.96	8,572.18	1,260.11	16,234.73	17,463.09
		5020016	Dolet Hills Misc Reagents	32,080.48	(3,434.16)	3,048.50	11,288.29	7,213.12	(7,120.85)	4,828.08	(1,408.87)
		5020025	Steam Exp Environmental	5,491.92	102,979.47	22,231.21	5,534.33	12,782.18	13,370.41	19,895.67	9,068.88
	5020 Total			**22,613,627.05**	**21,031,222.24**	**2,148,921.84**	**1,763,983.07**	**1,770,079.09**	**1,410,542.28**	**1,997,544.19**	**2,162,975.35**
5050	**Electric Expenses**	5050000	Electric Expenses	9,504,995.93	8,979,008.50	1,106,233.47	727,168.25	891,060.45	855,195.99	802,129.63	879,489.54
	5050 Total			**9,504,995.93**	**8,979,008.50**	**1,106,233.47**	**727,168.25**	**891,060.45**	**855,195.99**	**802,129.63**	**879,489.54**
5060	**Misc Steam Power Expenses**	5060000	Misc Steam Power Expenses	18,265,067.48	18,654,772.90	672,505.44	1,201,237.57	1,436,104.27	1,349,760.43	1,093,922.08	1,785,288.20
		5060001	Dresden Misc Steam Pwer Exp	7,095.00							
		5060003	Removal Cost Expense - Steam	41.84	(561.77)	(216.48)				818.16	(818.16)
	5060 Total			**18,272,204.32**	**18,654,211.13**	**672,288.96**	**1,201,237.57**	**1,436,104.27**	**1,349,760.43**	**1,094,740.24**	**1,784,470.04**
5070	**Rents**	5070000	Rents	530,604.00	180,405.36						
		5070006	Rents - Associated			267.02	267.02	267.02	267.02	267.02	267.02
	5070 Total			**530,604.00**	**180,405.36**	**267.02**	**267.02**	**267.02**	**267.02**	**267.02**	**267.02**
5080	**Operations - Supplies and Expenses**	5080017	IPP Oper - Training/Travel	53.81							
	5080 Total			**53.81**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
5090		5090001	Allowance Consumption - NOx		(0.01)						
	Allowance Consumption SO2	5090008	Deferred Enviro Emission Costs	(15,921.38)	(25,462.24)	177,140.04	(29,130.20)	(46,214.72)	179,077.42	(71,400.80)	(152,057.23)
		5090012	CSAPR AN NOx Cons. Exp	19,017.69	(4.05)						
		5090013	CSAPR Seasonal NOx Cons. Exp	197,855.28	341,055.56		(313.47)			21,492.74	42,898.03
	5090 Total			**200,951.59**	**315,589.26**	**177,140.04**	**(29,443.67)**	**(46,214.72)**	**179,077.42**	**(49,908.06)**	**(109,159.20)**
5100	**Maint Supv & Engineering**	5100000	Maint Supv & Engineering	6,197,465.88	5,934,152.55	625,149.47	494,414.59	518,598.16	510,102.33	492,945.31	519,494.83
		5100001	Dresden Maint Sup& Engineer		492.68						
	5100 Total			**6,197,465.88**	**5,934,645.23**	**625,149.47**	**494,414.59**	**518,598.16**	**510,102.33**	**492,945.31**	**519,494.83**
5110	**Maintenance of Structures**	5110000	Maintenance of Structures	8,901,219.44	6,643,125.58	345,604.63	390,582.29	534,723.67	467,978.45	702,385.27	754,637.02
	5110 Total			**8,901,219.44**	**6,643,125.58**	**345,604.63**	**390,582.29**	**534,723.67**	**467,978.45**	**702,385.27**	**754,637.02**
5120	**Maintenance of Boiler Plant**	5120000	Maintenance of Boiler Plant	50,051,718.78	37,897,423.56	2,899,085.80	3,866,872.42	1,703,742.69	3,247,977.06	3,958,460.92	3,739,638.77
		5120025	Maint of Blr Plt Environmental	5,787.55	4,698.58	75.06	87.53			633.13	
	5120 Total			**50,057,506.33**	**37,902,122.14**	**2,899,160.86**	**3,866,959.95**	**1,703,742.69**	**3,247,977.06**	**3,959,094.05**	**3,739,638.77**
5130	**Maintenance of Electric Plant**	5130000	Maintenance of Electric Plant	12,839,582.55	14,191,156.57	314,360.67	808,818.03	826,412.96	1,214,840.68	1,267,724.54	973,363.49
	5130 Total			**12,839,582.55**	**14,191,156.57**	**314,360.67**	**808,818.03**	**826,412.96**	**1,214,840.68**	**1,267,724.54**	**973,363.49**
5140	**Maintenance of Misc Steam Plt**	5140000	Maintenance of Misc Steam Plt	7,873,524.81	7,312,765.42	522,257.23	578,058.76	500,199.71	548,805.90	502,790.94	500,431.44
	5140 Total			**7,873,524.81**	**7,312,765.42**	**522,257.23**	**578,058.76**	**500,199.71**	**548,805.90**	**502,790.94**	**500,431.44**
5460	**Oper Supervision & Engineering**	5460000	Oper Supervision & Engineering	5,857.35	9,044.38			7,811.30	518.16	612.10	(1,112.94)
	5460 Total			**5,857.35**	**9,044.38**	**-**	**-**	**7,811.30**	**518.16**	**612.10**	**(1,112.94)**
5470	**Fuel**	5470001	Fuel - Gas Turbine	3,893,319.31	1,919,555.45	351,245.23	43,435.80	1,318.31	159,312.65	446,837.68	134,067.24
		5470003	Gas Transp Res Fees - CT	10,215,725.68	16,810,445.46	2,450,792.54	170,486.14	1,455,874.82	1,282,131.18	1,227,648.30	1,210,186.24
		5470005	Gas Transp Fees - CT	990,235.43	413,620.98	31,642.83	1.07		28,112.53	111,130.16	25,761.55
	5470 Total			**15,099,280.42**	**19,143,621.89**	**2,833,680.60**	**213,923.01**	**1,457,193.13**	**1,469,556.36**	**1,785,616.14**	**1,370,015.03**
5480	**Generation Expenses**	5480000	Generation Expenses	214,575.16	177,779.17	18,822.38	22,312.82	9,365.56	16,698.81	17,243.70	17,436.72
	5480 Total			**214,575.16**	**177,779.17**	**18,822.38**	**22,312.82**	**9,365.56**	**16,698.81**	**17,243.70**	**17,436.72**
5530	**Maintenance of Generating Plt**	5530001	Maint of Gen Plant - Gas Turb	816,618.70	786,914.81	118,671.26	52,250.42	74,907.35	37,125.35	49,164.30	58,416.37
	5530 Total			**816,618.70**	**786,914.81**	**118,671.26**	**52,250.42**	**74,907.35**	**37,125.35**	**49,164.30**	**58,416.37**
5540	**Maint of Misc Oth Pwr Gneratn**	5540001	Maint of Oth Pwr Gen Plt-GT	18,083.73	29,303.07	4,057.49	196.14	6,672.53	2,246.79	1,785.73	1,637.05
	5540 Total			**18,083.73**	**29,303.07**	**4,057.49**	**196.14**	**6,672.53**	**2,246.79**	**1,785.73**	**1,637.05**

Southerwestern Electric Power Company
Trial Balance - Income Statement
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

FERC	FERC Title	Account	Description	YTD 12/31/2016	YTD 12/31/2017	1/31/2018	2/28/2018	3/31/2018	4/30/2018	5/31/2018	6/30/2018
5550	**Purchased Power**	5550001	Purch Pwr-NonTrading-Nonassoc	52,239,651.83	64,749,523.25	6,394,708.63	2,403,256.43	3,776,767.95	7,621,810.42	16,394,317.52	6,964,853.95
		5550003	Purchased Power - Cogeneration	99,503.83	243,537.13	16,559.93	18,743.35	12,821.32	9,829.48	27,761.16	30,775.94
		5550023	Purch Power Capacity -NA	13,424,037.15	10,365,798.67	759,420.34	755,848.30	752,563.21	752,571.00	752,600.44	752,600.17
		5550024	Purchase Power ERCOT	2,313.54	20,281.78	825.77	170.35		1.48	(0.66)	7.05
		5550026	Purchase Power - Fuel - ERCOT	532,609.96	459,876.58	89,859.95	64,869.45	90,959.51	35,429.40	9.65	91,572.09
		5550029	Purch Power-Assoc-Trnsfr Price	0.00	0.00	-	-	-	(0.00)	-	-
		5550032	Gas-Conversion-Mone Plant	(0.22)	(24.52)	2.70	(17.43)				
		5550047	Purchase Power Wind Energy	63,565,469.95	65,829,880.62	7,086,810.19	6,031,175.65	6,530,845.35	6,899,117.60	6,007,873.38	6,614,130.18
		5550054	Purch Power ERCOT-Non-ded	792.29	4,344.84	(3,692.59)	0.02		0.01	1,272.46	
		5550066	SPP Rev. Neutrality Ded-Purch	2,036,281.89	6,424,723.06	1,425,803.19	229,363.06	(114,610.84)	344,958.87	367,339.03	636,200.37
		5550113	Cleco PP for Valley - Other		(311,781.61)						
		5550128	SPP Net Purch that serve OSS	17,038,159.96	20,164,688.52	2,129,688.04	2,733,581.48	1,348,200.40	1,593,371.47	1,047,347.46	2,558,061.22
		5550130	SPP Net Marginal Losses LSE	8,621,579.44	8,075,826.37	1,086,463.91	445,751.08	446,747.48	347,560.22	167,733.15	370,487.26
		5550131	SPP Congestion Costs LSE	15,729,853.92	29,504,587.31	2,358,218.43	1,874,839.39	522,217.32	3,234,873.05	492,121.78	136,833.08
		5550133	SPP TCR's & ARR's LSE	(17,067,630.79)	(22,566,578.80)	(1,164,542.34)	(766,735.30)	1,119.41	1,511,524.42	2,416,754.84	(10,482,589.06)
		5550136	SPP MakeWholePymt Charge Gross	3,582,777.94	3,420,421.37	761,994.56	248,587.47	182,025.84	186,048.41	255,149.51	280,734.01
		5550138	SPP MakeWholePymt Credit (Net)	(3,691,086.92)	(1,966,484.59)	(557,623.62)	(91,925.24)	(182,891.93)	(211,859.76)	(232,911.20)	(290,718.86)
		5550320	SPP Net Regulation LSE	2,237,473.96	2,871,112.02	253,391.78	200,627.78	240,166.63	152,046.08	213,390.34	295,513.34
		5550321	SPP Net Spinning Reserve LSE	606,731.57	1,029,870.41	178,708.11	121,327.50	33,299.49	43,294.48	42,240.89	75,744.07
		5550324	SPP Net Supp Reserve LSE	402,211.97	476,317.23	48,964.99	28,891.60	24,661.05	16,620.38	51,551.35	56,006.34
		5550325	SPP Contingency Costs LSE	66,394.79	118,523.50	6,178.20	3,385.40	44,340.70	5,661.74	(3,994.86)	(2,192.91)
	5550 Total			**159,427,126.06**	**188,914,443.14**	**20,871,740.17**	**14,301,740.34**	**13,709,232.89**	**22,542,858.75**	**28,000,556.24**	**8,088,018.24**
5560	**Sys Control & Load Dispatching**	5560000	Sys Control & Load Dispatching	1,880,465.05	1,677,405.12	196,168.12	141,362.25	155,472.11	158,216.91	165,882.98	138,625.30
	5560 Total			**1,880,465.05**	**1,677,405.12**	**196,168.12**	**141,362.25**	**155,472.11**	**158,216.91**	**165,882.98**	**138,625.30**
5570	**Other Expenses**	5570000	Other Expenses	4,215,829.87	3,467,056.55	363,061.66	281,596.73	241,481.68	306,084.40	296,829.73	258,974.89
		5570004	Deferred Fuel	(979,397.01)	3,167,220.52	(2,402,006.75)	(2,610,700.27)	3,027,522.03	1,999,443.32	(1,748,912.08)	2,797,870.49
		5570010	OH Auction Exp - Incremental		9.62						
	5570 Total			**3,236,432.86**	**6,634,286.69**	**(2,038,945.09)**	**(2,329,103.54)**	**3,269,003.71**	**2,305,527.72**	**(1,452,082.35)**	**3,056,845.38**
5600	**Oper Supervision & Engineering**	5600000	Oper Supervision & Engineering	4,711,396.41	7,229,054.20	375,576.48	763,624.25	715,892.20	938,956.70	889,892.76	937,536.66
	5600 Total			**4,711,396.41**	**7,229,054.20**	**375,576.48**	**763,624.25**	**715,892.20**	**938,956.70**	**889,892.76**	**937,536.66**
5611	**Load Dispatching**	5611000	Load Dispatch - Reliability	38,666.23	4,943.63			58.86	(7.55)		
	5611 Total			**38,666.23**	**4,943.63**	**-**	**-**	**58.86**	**(7.55)**	**-**	**-**
5612	**Load Dispatching**	5612000	Load Dispatch-Mntr&Op TransSys	3,029,374.12	995,895.65	85,316.77	55,005.23	57,181.39	75,490.36	67,871.43	76,238.52
	5612 Total			**3,029,374.12**	**995,895.65**	**85,316.77**	**55,005.23**	**57,181.39**	**75,490.36**	**67,871.43**	**76,238.52**
5613	**Load Dispatching**	5613000	Load Dispatch-Trans Srvc&Sched	516.02	759.44	64.53	8,552.27	(8,304.98)	29.68	35.82	35.82
	5613 Total			**516.02**	**759.44**	**64.53**	**8,552.27**	**(8,304.98)**	**29.68**	**35.82**	**35.82**
5614	**Load Dispatching**	5614002	SPP Admin-SSC&DS	10,343,953.82	11,629,640.69	1,001,719.66	953,907.69	782,269.50	1,055,649.69	903,916.34	996,632.21
		5614005	ERCOT Admin-SSC&DS	3,188.85	11,712.02	3,408.13	1,529.92		0.01	0.30	0.18
		5614006	SPP Transmission Charges	216,173.35	237,351.33	21,372.35	(18,505.05)	123.35	119.09	169.68	(470.33)
		5614007	RTO Admin Default LSE.		(68,040.42)						
	5614 Total			**10,563,316.02**	**11,810,663.62**	**1,026,500.14**	**936,932.56**	**782,392.85**	**1,055,768.79**	**904,086.32**	**996,162.06**
5615	**Load Dispatching**	5615000	Reliability,Plng&Stds Develop	180,575.59	126,145.52	10,676.64	9,382.23	8,716.16	13,875.23	9,672.38	9,252.23
	5615 Total			**180,575.59**	**126,145.52**	**10,676.64**	**9,382.23**	**8,716.16**	**13,875.23**	**9,672.38**	**9,252.23**
5616	**Load Dispatching**	5616000	Transmission Service Studies		10.25	55.09	(15.76)				
	5616 Total			**-**	**10.25**	**55.09**	**(15.76)**	**-**	**-**	**-**	**-**
5618	**Load Dispatching**	5618002	SPP Admin-RP&SDS	948,463.76	1,046,344.95	90,002.41	90,002.41	90,002.41	90,002.42	90,002.41	90,002.42
	5618 Total			**948,463.76**	**1,046,344.95**	**90,002.41**	**90,002.41**	**90,002.41**	**90,002.42**	**90,002.41**	**90,002.42**
5620	**Station Expenses**	5620001	Station Expenses - Nonassoc	587,166.89	589,211.11	69,031.57	28,275.51	57,424.31	94,985.92	36,478.52	178,299.32
	5620 Total			**587,166.89**	**589,211.11**	**69,031.57**	**28,275.51**	**57,424.31**	**94,985.92**	**36,478.52**	**178,299.32**
5630	**Overhead Line Expenses**	5630000	Overhead Line Expenses	535,361.97	313,247.97	61,188.39	12,267.62	19,098.04	67,376.36	105,811.35	72,833.10
	5630 Total			**535,361.97**	**313,247.97**	**61,188.39**	**12,267.62**	**19,098.04**	**67,376.36**	**105,811.35**	**72,833.10**

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5640	**Underground Line Expenses**	5640000	Underground Line Expenses	254.21							
	5640 Total			**254.21**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
5650	**Trnsmssion of Elect by Others**	5650001	Transmssn Elec by Others-Assoc	44,208.48	44,208.48	3,684.04	3,684.04	3,684.04	3,684.04	3,684.04	3,684.04
		5650002	Transmssn Elec by Others-NAC	5,955,533.56	5,325,940.70	835,800.51	553,977.38	421,601.17	330,798.01	546,606.23	573,220.06
		5650007	Tran Elec by Oth-Aff-Trn Price	(0.00)	0.00	-	-	-	-	-	0.00
		5650009	SPP Affiliated Transmission Ex	16,316,080.12	23,432,649.13	2,971,607.81	2,302,831.77	2,046,515.71	1,822,126.84	2,835,992.67	(4,615,493.83)
		5650010	Tran Elec by Oth-Aff-SPP	(0.00)	(0.00)	-	-	-	-	-	-
		5650013	SPP Affil. Base Funding Exp	7,064,368.22	7,298,031.95	759,045.57	796,246.58	851,943.24	800,921.60	812,750.56	3,577,899.23
		5650014	SPP Non-Affil Base Funding Exp	52,020,744.52	51,547,777.12	3,476,543.73	5,159,537.21	4,304,388.63	4,389,697.52	4,309,863.63	4,176,556.01
		5650016	PJM NITS Expense - Affiliated								2,582,226.00
		5650020	PROVISION RTO Affl Expense	(58,523.92)	706,456.84	(5,939.49)	9,734.05	(8,694.61)	5,207.64	5,280.93	(74,114.74)
		5650046	SPP Transmission Expense	3,780,647.92	3,607,964.58	185,884.04	490,859.17	279,295.65	274,417.65	197,068.70	373,777.97
		5650047	SPP Pt to Pt Trans Affil Exp	(1,959.24)	1,023.85						
		5650048	Affil. SPPAncillary Sch. 1 Exp	9,751.86	1,751.39						
		5650052	SPP Transmission - Contra		(8,428,833.46)						
	5650 Total			**85,130,851.51**	**83,536,970.58**	**8,226,626.21**	**9,316,870.20**	**7,898,733.83**	**7,626,853.30**	**8,711,246.76**	**6,597,754.74**
5660	**Misc Transmission Expenses**	5660000	Misc Transmission Expenses	4,639,802.63	2,668,395.01	(64,153.64)	132,136.86	205,791.38	193,496.75	262,995.07	354,984.12
		5660004	SPP FERC Assessment Fees	20.53							
		5660008	R.King Trans Cnter Exp - Affil	65.71							
	5660 Total			**4,639,888.87**	**2,668,395.01**	**(64,153.64)**	**132,136.86**	**205,791.38**	**193,496.75**	**262,995.07**	**354,984.12**
5670	**Rents**	5670001	Rents - Nonassociated	23,445.85	6,931.38	24,343.41					12,462.87
		5670002	Rents - Associated		88,187.64	7,112.16	(7,112.16)	0.00	0.00	0.00	0.00
	5670 Total			**23,445.85**	**95,119.02**	**31,455.57**	**(7,112.16)**	**0.00**	**0.00**	**0.00**	**12,462.87**
5680	**Maint Supv & Engineering**	5680000	Maint Supv & Engineering	28,644.51	1,655.74	1,260.94	8,754.29	4,801.42	7,839.04	5,000.20	5,964.91
	5680 Total			**28,644.51**	**1,655.74**	**1,260.94**	**8,754.29**	**4,801.42**	**7,839.04**	**5,000.20**	**5,964.91**
5690	**Maintenance of Structures**	5690000	Maintenance of Structures	59,554.58	111,919.24	312.89	5,420.32	(494.43)	422.87	43,667.60	1,109.46
	5690 Total			**59,554.58**	**111,919.24**	**312.89**	**5,420.32**	**(494.43)**	**422.87**	**43,667.60**	**1,109.46**
5691	**Maintenance of Structures**	5691000	Maint of Computer Hardware	2,333.98	3,812.80	625.54	213.53	(1,022.52)	184.36	1,000.66	1,133.31
	5691 Total			**2,333.98**	**3,812.80**	**625.54**	**213.53**	**(1,022.52)**	**184.36**	**1,000.66**	**1,133.31**
5692	**Maintenance of Structures**	5692000	Maint of Computer Software	962,663.00	456,734.19	125,571.88	31,400.45	34,829.86	41,373.52	19,979.76	33,129.76
	5692 Total			**962,663.00**	**456,734.19**	**125,571.88**	**31,400.45**	**34,829.86**	**41,373.52**	**19,979.76**	**33,129.76**
5693	**Maintenance of Structures**	5693000	Maint of Communication Equip	76,754.06	25,121.75	10,534.83	2,866.74	(4,853.86)	5,493.94	4,787.72	4,809.76
	5693 Total			**76,754.06**	**25,121.75**	**10,534.83**	**2,866.74**	**(4,853.86)**	**5,493.94**	**4,787.72**	**4,809.76**
5700	**Maint of Station Equipment**	5700000	Maint of Station Equipment	2,305,984.93	2,491,427.68	288,034.43	132,943.87	113,338.57	144,036.94	150,899.73	155,204.98
	5700 Total			**2,305,984.93**	**2,491,427.68**	**288,034.43**	**132,943.87**	**113,338.57**	**144,036.94**	**150,899.73**	**155,204.98**
5710	**Maintenance of Overhead Lines**	5710000	Maintenance of Overhead Lines	6,344,240.57	8,217,454.99	622,986.68	735,375.01	873,563.67	512,588.28	686,999.92	1,216,044.85
	5710 Total			**6,344,240.57**	**8,217,454.99**	**622,986.68**	**735,375.01**	**873,563.67**	**512,588.28**	**686,999.92**	**1,216,044.85**
5720	**Maint of Underground Lines**	5720000	Maint of Underground Lines	131.68	617.88	2,186.37	(1,002.82)	(887.49)	114.08	245.49	(107.61)
	5720 Total			**131.68**	**617.88**	**2,186.37**	**(1,002.82)**	**(887.49)**	**114.08**	**245.49**	**(107.61)**
5730	**Maint of Misc Trnsmssion Plt**	5730000	Maint of Misc Trnsmssion Plt	131,201.23	46,781.12	7,863.00	13,382.98	3,867.24	3,563.96	1,536.29	4,672.85
	5730 Total			**131,201.23**	**46,781.12**	**7,863.00**	**13,382.98**	**3,867.24**	**3,563.96**	**1,536.29**	**4,672.85**
5757	**SPP Admin-MAM&SC**	5757002	SPP Admin-MAM&SC	1,141,445.53	1,118,077.33	82,167.82	62,498.55	263,751.13	135,066.57	(83,320.62)	279,948.39
	5757 Total			**1,141,445.53**	**1,118,077.33**	**82,167.82**	**62,498.55**	**263,751.13**	**135,066.57**	**(83,320.62)**	**279,948.39**
5800	**Oper Supervision & Engineering**	5800000	Oper Supervision & Engineering	1,731,147.71	2,241,206.14	(337.92)	158,170.77	211,012.78	379,341.78	186,767.98	903,817.77
	5800 Total			**1,731,147.71**	**2,241,206.14**	**(337.92)**	**158,170.77**	**211,012.78**	**379,341.78**	**186,767.98**	**903,817.77**
5810	**Load Dispatching**	5810000	Load Dispatching	133,632.59	70,613.74	5,827.40	2,687.93	4,325.34	6,026.53	3,726.74	4,247.76
	5810 Total			**133,632.59**	**70,613.74**	**5,827.40**	**2,687.93**	**4,325.34**	**6,026.53**	**3,726.74**	**4,247.76**
5820	**Station Expenses**	5820000	Station Expenses	672,573.37	779,379.19	77,744.06	51,264.05	51,451.87	68,612.00	38,852.59	57,447.24

Southerwestern Electric Power Company
Trial Balance - Income Statement
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

FERC	FERC Title	Account	Description	YTD 12/31/2016	YTD 12/31/2017	1/31/2018	2/28/2018	3/31/2018	4/30/2018	5/31/2018	6/30/2018
	5820 Total			**672,573.37**	**779,379.19**	**77,744.06**	**51,264.05**	**51,451.87**	**68,612.00**	**38,852.59**	**57,447.24**
5830	**Overhead Line Expenses**	5830000	Overhead Line Expenses	2,370,810.70	3,744,245.23	60,299.35	105,506.60	111,156.12	(82,345.13)	(56,288.04)	87,603.80
	5830 Total			**2,370,810.70**	**3,744,245.23**	**60,299.35**	**105,506.60**	**111,156.12**	**(82,345.13)**	**(56,288.04)**	**87,603.80**
5840	**Underground Line Expenses**	5840000	Underground Line Expenses	1,728,972.92	1,616,095.87	145,336.36	134,827.49	138,538.47	121,055.63	157,326.92	137,088.89
	5840 Total			**1,728,972.92**	**1,616,095.87**	**145,336.36**	**134,827.49**	**138,538.47**	**121,055.63**	**157,326.92**	**137,088.89**
5850	**Street Lighting & Signal Sys E**	5850000	Street Lighting & Signal Sys E	349,690.78	213,708.96	18,831.58	11,542.69	11,117.81	8,152.70	13,075.26	12,235.73
	5850 Total			**349,690.78**	**213,708.96**	**18,831.58**	**11,542.69**	**11,117.81**	**8,152.70**	**13,075.26**	**12,235.73**
5860	**Meter Expenses**	5860000	Meter Expenses	3,432,425.80	3,755,625.49	362,193.43	276,064.94	314,805.19	274,273.84	301,847.82	315,445.75
	5860 Total			**3,432,425.80**	**3,755,625.49**	**362,193.43**	**276,064.94**	**314,805.19**	**274,273.84**	**301,847.82**	**315,445.75**
5870	**Customer Installations Exp**	5870000	Customer Installations Exp	716,791.05	581,211.34	63,098.31	44,495.61	48,803.49	32,033.39	50,509.52	47,603.71
	5870 Total			**716,791.05**	**581,211.34**	**63,098.31**	**44,495.61**	**48,803.49**	**32,033.39**	**50,509.52**	**47,603.71**
5880	**Miscellaneous Distribution Exp**	5880000	Miscellaneous Distribution Exp	20,617,686.01	19,840,543.17	1,110,649.99	1,651,056.93	1,873,298.02	2,159,469.85	997,716.41	1,808,425.05
	5880 Total			**20,617,686.01**	**19,840,543.17**	**1,110,649.99**	**1,651,056.93**	**1,873,298.02**	**2,159,469.85**	**997,716.41**	**1,808,425.05**
5890	**Rents**	5890001	Rents - Nonassociated	848,056.63	865,127.80	61,322.31	82,411.33	79,102.92	72,763.82	72,761.12	72,754.00
		5890002	Rents - Associated	21,759.72	22,244.64	1,826.30	1,826.30	1,826.30	1,826.30	1,826.30	1,826.30
	5890 Total			**869,816.35**	**887,372.44**	**63,148.61**	**84,237.63**	**80,929.22**	**74,590.12**	**74,587.42**	**74,580.30**
5900	**Maint Supv & Engineering**	5900000	Maint Supv & Engineering	268,706.56	227,732.10	22,282.02	27,133.50	22,919.81	33,790.67	40,157.40	15,512.59
	5900 Total			**268,706.56**	**227,732.10**	**22,282.02**	**27,133.50**	**22,919.81**	**33,790.67**	**40,157.40**	**15,512.59**
5910	**Maintenance of Structures**	5910000	Maintenance of Structures	70,671.75	118,212.36	3,202.26	3,746.83	(1,309.73)	5,184.58	8,374.03	878.73
	5910 Total			**70,671.75**	**118,212.36**	**3,202.26**	**3,746.83**	**(1,309.73)**	**5,184.58**	**8,374.03**	**878.73**
5920	**Maint of Station Equipment**	5920000	Maint of Station Equipment	1,250,957.90	1,279,042.53	82,450.47	64,943.97	61,235.79	73,079.74	104,465.79	124,412.07
	5920 Total			**1,250,957.90**	**1,279,042.53**	**82,450.47**	**64,943.97**	**61,235.79**	**73,079.74**	**104,465.79**	**124,412.07**
5930	**Maintenance of Overhead Lines**	5930000	Maintenance of Overhead Lines	40,019,821.89	47,752,112.63	3,860,406.98	2,823,517.49	3,293,375.31	4,415,906.31	3,743,652.38	4,145,440.36
		5930007	Mnt O/H Line Reliability-Def		741.40						
	5930 Total			**40,019,821.89**	**47,752,854.03**	**3,860,406.98**	**2,823,517.49**	**3,293,375.31**	**4,415,906.31**	**3,743,652.38**	**4,145,440.36**
5940	**Maint of Underground Lines**	5940000	Maint of Underground Lines	1,426,954.40	1,134,196.85	95,857.13	57,027.16	86,018.73	62,717.13	95,661.55	60,465.80
	5940 Total			**1,426,954.40**	**1,134,196.85**	**95,857.13**	**57,027.16**	**86,018.73**	**62,717.13**	**95,661.55**	**60,465.80**
5950	**Maint of Lne Trnf,Rglators&Dvi**	5950000	Maint of Lne Trnf,Rglators&Dvi	298,981.58	287,928.20	22,317.92	11,586.34	18,973.80	21,187.04	17,505.55	21,703.85
	5950 Total			**298,981.58**	**287,928.20**	**22,317.92**	**11,586.34**	**18,973.80**	**21,187.04**	**17,505.55**	**21,703.85**
5960	**Maint of Strt Lghtng & Sgnal S**	5960000	Maint of Strt Lghtng & Sgnal S	406,013.71	622,327.73	50,711.98	57,784.26	44,592.36	21,664.38	45,211.69	25,892.30
	5960 Total			**406,013.71**	**622,327.73**	**50,711.98**	**57,784.26**	**44,592.36**	**21,664.38**	**45,211.69**	**25,892.30**
5970	**Maintenance of Meters**	5970000	Maintenance of Meters	511,598.57	476,953.43	59,440.99	38,690.74	34,587.56	36,274.88	38,939.82	34,525.76
	5970 Total			**511,598.57**	**476,953.43**	**59,440.99**	**38,690.74**	**34,587.56**	**36,274.88**	**38,939.82**	**34,525.76**
5980	**Maint of Misc Distribution Plt**	5980000	Maint of Misc Distribution Plt	320,574.49	283,522.97	23,364.21	24,739.54	25,106.38	22,781.65	22,069.84	22,480.49
	5980 Total			**320,574.49**	**283,522.97**	**23,364.21**	**24,739.54**	**25,106.38**	**22,781.65**	**22,069.84**	**22,480.49**
9010	**Supervision - Customer Accts**	9010000	Supervision - Customer Accts	705,614.34	712,898.86	65,653.03	54,027.34	58,743.12	56,264.03	61,217.15	61,771.99
	9010 Total			**705,614.34**	**712,898.86**	**65,653.03**	**54,027.34**	**58,743.12**	**56,264.03**	**61,217.15**	**61,771.99**
9020	**Meter Reading Expenses**	9020000	Meter Reading Expenses	326,296.20	251,422.75	21,228.50	44,286.22	13,652.52	19,419.01	12,572.66	29,296.73
		9020001	Customer Card Reading	304.23							
		9020002	Meter Reading - Regular	1,795,015.81	1,641,967.15	179,892.38	117,765.92	142,622.55	137,556.67	147,940.04	166,300.47
		9020003	Meter Reading - Large Power	85,180.06	95,247.52	7,110.34	4,728.45	4,184.80	5,941.70	5,861.11	7,382.09
		9020004	Read-In & Read-Out Meters	37,404.50	13,702.09	724.54	(62.90)	(6.31)	(6.11)		1,205.19
	9020 Total			**2,244,200.80**	**2,002,339.51**	**208,955.76**	**166,717.69**	**160,453.56**	**162,911.27**	**166,373.81**	**204,184.48**
9030	**Cust Records & Collection Exp**	9030000	Cust Records & Collection Exp	2,161,434.71	1,820,204.49	180,214.49	152,182.07	164,691.55	196,498.28	148,646.12	149,122.21

Southerwestern Electric Power Company
Trial Balance - Income Statement
Test Year Ending December 31, 2018
Docket No. 19-008-U

Schedule E-17A

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

FERC	FERC Title	Account	Description	YTD 12/31/2016	YTD 12/31/2017	1/31/2018	2/28/2018	3/31/2018	4/30/2018	5/31/2018	6/30/2018
		9030001	Customer Orders & Inquiries	8,676,933.00	8,680,239.20	791,824.86	765,352.46	873,829.10	695,577.68	721,723.42	705,291.89
		9030002	Manual Billing	85,603.57	84,212.37	6,799.68	5,748.28	6,775.47	6,620.37	7,199.91	5,211.32
		9030003	Postage - Customer Bills	1,949,354.32	1,799,591.69	135,442.67	129,509.94	137,557.98	137,998.36	134,836.00	138,397.12
		9030004	Cashiering	232,296.36	301,489.70	22,663.57	19,201.90	19,583.56	18,785.01	18,313.72	9,986.95
		9030005	Collection Agents Fees & Exp	280,766.60	237,658.06	16,646.33	18,125.58	18,788.41	18,244.49	15,543.26	16,952.64
		9030006	Credit & Oth Collection Activi	2,149,413.80	2,277,629.04	160,071.96	197,410.11	227,130.01	210,361.38	215,107.34	192,507.46
		9030007	Collectors	1,162,317.17	912,077.31	77,652.77	67,973.09	86,850.42	64,213.97	49,501.34	61,434.19
		9030009	Data Processing	484,265.62	576,223.86	41,460.69	31,329.61	46,486.71	33,058.92	37,114.17	43,526.22
		9030 Total		**17,182,385.15**	**16,689,325.72**	**1,432,777.02**	**1,386,833.04**	**1,581,693.21**	**1,381,358.46**	**1,347,985.28**	**1,322,430.00**
9040	**Uncollectible Accounts**	9040007	Uncoll Accts - Misc Receivable	223,225.39	450,348.79	(89,698.58)	(441,457.50)	3,216.23	2,734.82	(0.01)	0.22
		9040 Total		**223,225.39**	**450,348.79**	**(89,698.58)**	**(441,457.50)**	**3,216.23**	**2,734.82**	**(0.01)**	**0.22**
9050	**Misc Customer Accounts Exp**	9050000	Misc Customer Accounts Exp	119,565.24	92,675.75	7,001.57	6,297.08	5,153.44	11,421.92	17,205.46	1,804.99
		9050 Total		**119,565.24**	**92,675.75**	**7,001.57**	**6,297.08**	**5,153.44**	**11,421.92**	**17,205.46**	**1,804.99**
9070	**Supervision - Customer Service**	9070000	Supervision - Customer Service	728,376.06	678,923.07	60,503.32	60,608.58	57,982.92	62,941.08	82,275.25	66,551.69
		9070001	Supervision - DSM	6,202,399.78	5,898,786.60	62,955.74	423,404.79	768,157.07	765,894.01	679,916.27	681,240.47
		9070014	DSM Costs Deferred - TEXAS	(461,587.84)	(439,115.01)	418,789.76	93,180.59	(268,397.70)	(345,510.11)	(226,091.98)	107,015.45
		9070 Total		**6,469,188.00**	**6,138,594.66**	**542,248.82**	**577,193.96**	**557,742.29**	**483,324.98**	**536,099.54**	**854,807.61**
9080	**Customer Assistance Expenses**	9080000	Customer Assistance Expenses	3,412,593.47	(691,020.71)	185,151.88	133,476.74	157,017.00	152,363.98	170,345.01	155,839.61
		9080001	DSM-Customer Advisory Grp		332.42			46.04			
		9080004	Cust Assistnce Exp - DSM - Ind	(14.13)	488.64	948.85	(298.44)	(1,004.11)	(130.05)	(6.04)	
		9080009	Cust Assistance Expense - DSM	9,752,016.76	9,947,104.93	916,562.64	680,750.03	664,976.94	967,064.27	602,946.59	837,763.71
		9080014	DSM Costs Deferred	(2,449,609.62)	(156,441.58)	420,002.42	267,669.15	(154,298.53)	(43,553.11)	173,053.35	423,758.99
		9080 Total		**10,714,986.48**	**9,100,463.70**	**1,522,665.79**	**1,081,597.48**	**666,737.34**	**1,075,745.09**	**946,338.91**	**1,417,362.31**
9090	**Information & Instruct Advrtis**	9090000	Information & Instruct Advrtis	5,940.00							192.99
		9090 Total		**5,940.00**	**-**	**-**	**-**	**-**	**-**	**-**	**192.99**
9100	**Misc Cust Svc&Informational Ex**	9100000	Misc Cust Svc&Informational Ex	75,280.81	119,976.20	3,161.60	260.52	(1,921.30)	2,434.19	976.71	901.01
		9100001	Misc Cust Svc & Info Exp - RCS	2,919.32	2,720.50	14.67	7.71				
		9100 Total		**78,200.13**	**122,696.70**	**3,176.27**	**268.23**	**(1,921.30)**	**2,434.19**	**976.71**	**901.01**
9110	**Supervision - Sales Expenses**	9110001	Supervision - Residential				97.13	(71.73)	18.53	2.87	(9.96)
		9110002	Supervision - Comm & Ind	347.72	1,165.00		238.41	82.94			
		9110 Total		**347.72**	**1,165.00**	**-**	**335.54**	**11.21**	**18.53**	**2.87**	**(9.96)**
9120	**Demonstrating & Selling Exp**	9120000	Demonstrating & Selling Exp	117,061.54	147,735.29	34,398.61	16,100.11	10,369.88	10,119.59	9,267.14	16,318.11
		9120001	Demo & Selling Exp - Res		4,308.78					2.08	
		9120 Total		**117,061.54**	**152,044.07**	**34,398.61**	**16,100.11**	**10,369.88**	**10,119.59**	**9,269.22**	**16,318.11**
9130	**Advertising Exp**	9130001	Advertising Exp - Residential	1,013.03							
		9130 Total		**1,013.03**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
9200	**Administrative & Gen Salaries**	9200000	Administrative & Gen Salaries	28,787,046.49	27,861,379.16	3,044,702.45	2,121,212.37	2,090,873.40	2,396,960.66	2,288,896.11	2,469,918.89
		9200005	GridSmart Reimbursement Contra			966.77	1,672.25	1,229.08	1,139.65	(5,007.75)	
		9200 Total		**28,787,046.49**	**27,861,379.16**	**3,045,669.22**	**2,122,884.62**	**2,092,102.48**	**2,398,100.31**	**2,283,888.36**	**2,469,918.89**
9210	**Office Supplies and Expenses**	9210001	Off Supl & Exp - Nonassociated	2,467,524.14	2,514,174.20	489,791.81	310,167.78	53,268.16	213,317.55	276,270.31	84,180.85
		9210002	Off Supl & Exp - Associated	(60,556.02)	95,082.76	12,126.46	11,351.42	11,088.15	9,160.92	9,949.72	9,781.52
		9210003	Office Supplies & Exp - Trnsf	674.02	754.98	1.26	12.21			648.11	
		9210004	Office Utilites		160.93						
		9210005	Cellular Phones and Pagers	206.25	19.03						
		9210007	Dresden Off Supl & Exp Nonasoc				2.99				
		9210 Total		**2,407,848.39**	**2,610,191.90**	**501,919.53**	**321,534.40**	**64,356.31**	**222,478.47**	**286,868.14**	**93,962.37**
9220	**Administrative Exp Trnsf - Cr**	9220000	Administrative Exp Trnsf - Cr	(1,974,841.17)	(1,870,692.91)	(155,695.66)	(124,176.92)	(103,221.67)	(112,081.67)	(115,111.54)	(620,941.39)
		9220001	Admin Exp Trnsf to Cnstrction	(2,182,084.00)	(134,124.00)	(129,886.00)	(94,334.00)	(112,343.00)	(124,027.00)	(259,407.00)	(171,106.00)
		9220004	Admin Exp Trnsf to ABD	(32,346.91)	(14,343.67)	(1,022.31)	(1,289.52)	(2,881.21)	(1,170.94)	(2,043.00)	(2,078.82)
		9220 Total		**(4,189,272.08)**	**(2,019,160.58)**	**(286,603.97)**	**(219,800.44)**	**(218,445.88)**	**(237,279.61)**	**(376,561.54)**	**(794,126.21)**

Southwestern Electric Power Company
Trial Balance - Income Statement
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

FERC	FERC Title	Account	Description	YTD 12/31/2016	YTD 12/31/2017	1/31/2018	2/28/2018	3/31/2018	4/30/2018	5/31/2018	6/30/2018
9230	**Outside Services Employed**	9230001	Outside Svcs Empl - Nonassoc	5,654,670.63	6,083,561.33	367,079.26	475,447.70	391,528.74	439,265.56	632,752.49	492,436.27
		9230003	AEPSC Billed to Client Co	887,780.46	(129,096.37)	(538,640.39)	531,362.74	146,219.98	158,833.39	(296,727.26)	(266,546.55)
	9230 Total			**6,542,451.09**	**5,954,464.96**	**(171,561.13)**	**1,006,810.44**	**537,748.72**	**598,098.95**	**336,025.23**	**225,889.72**
9240	**Property Insurance**	9240000	Property Insurance	2,813,734.40	1,144,529.30	170,388.66	173,509.24	173,505.90	162,881.72	536,112.41	199,960.72
	9240 Total			**2,813,734.40**	**1,144,529.30**	**170,388.66**	**173,509.24**	**173,505.90**	**162,881.72**	**536,112.41**	**199,960.72**
9250	**Injuries and Damages**	9250000	Injuries and Damages	3,417,185.02	3,669,980.78	299,200.27	310,752.87	136,888.44	307,660.33	303,413.18	208,239.20
		9250001	Safety Dinners and Awards	939.52	440.62			86.14			17.34
		9250002	Emp Accdent Prvntion-Adm Exp	166,159.19	240,202.45	7,657.09	18,647.42	21,371.93	21,530.77	31,927.53	37,708.03
		9250004	Injuries to Employees							-	-
		9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	529,209.45	572,488.27	(26,766.42)	15,979.79	83,754.71	29,636.30	537,560.19	13,383.63
		9250007	Prsnal Injries&Prop Dmage-Pub	1,311,689.89	47,221.13	12,505.50	(12,103.06)	18,335.61	25,141.65	26,100.74	15,067.12
		9250010	Frg Ben Loading - Workers Comp	(201,028.07)	(177,980.29)	(10,241.80)	(9,886.58)	(14,889.14)	(15,497.68)	(16,820.42)	(15,651.93)
	9250 Total			**5,224,155.00**	**4,352,352.96**	**282,354.64**	**323,390.44**	**245,547.69**	**368,471.37**	**882,181.22**	**258,763.39**
9260	**Employee Pensions & Benefits**	9260000	Employee Pensions & Benefits	(1,396,980.12)	(1,470,352.98)	(139,065.60)	(82,653.62)	(104,125.82)	(58,281.69)	(103,970.64)	(100,330.02)
		9260001	Edit & Print Empl Pub-Salaries	64,398.07	63,817.51	6,204.55	3,795.53	4,846.56	4,727.78	5,464.49	3,826.88
		9260002	Pension & Group Ins Admin	83,970.73	60,532.75	22,884.78	1,836.64	6,421.30	(759.19)	9,508.33	3,098.10
		9260003	Pension Plan	9,060,820.74	8,857,776.44	800,430.59	800,430.59	709,790.82	770,217.33	770,217.33	770,217.33
		9260004	Group Life Insurance Premiums	498,623.49	512,324.26	43,272.02	44,134.23	44,668.61	42,645.80	44,246.58	45,184.79
		9260005	Group Medical Ins Premiums	16,419,620.30	15,033,905.35	1,130,335.61	1,317,885.66	1,361,749.97	1,322,489.03	1,309,718.99	1,316,083.53
		9260006	Physical Examinations		2,977.81						
		9260007	Group L-T Disability Ins Prem	923.72	481,017.79	46,782.33	42,161.65	42,548.39	49,893.64	53,054.19	58,306.67
		9260009	Group Dental Insurance Prem	321,374.56	614,725.14	61,099.46	62,251.57	62,098.54	61,788.72	61,346.79	61,083.56
		9260010	Training Administration Exp	727,373.52	5,573.72	99.48	53.78	233.95	337.56	1,438.63	(585.82)
		9260012	Employee Activities	6,138.09	47,297.28	5,032.28	5,664.29	3,834.97	6,527.53	5,501.85	1,868.03
		9260014	Educational Assistance Pmts	18,042.15	101,070.01	27,606.79		8,534.31	2,256.62	23,955.24	5,748.87
		9260021	Postretirement Benefits - OPEB	87,033.13	(4,775,381.30)	81,949.16	81,949.16	60,988.93	74,962.41	74,962.41	74,962.41
		9260026	Savings Plan Administration	(5,375,048.17)			(109.82)				
		9260027	Savings Plan Contributions	5,783,971.98	5,777,250.24	450,947.72	449,603.14	662,102.57	496,542.71	476,694.14	497,100.83
		9260036	Deferred Compensation	12,540.24	13,921.80			61.55			4,188.75
		9260037	Supplemental Pension	136,290.00	183,258.97	3,731.33	3,731.33	319.59	2,594.08	2,594.08	2,594.08
		9260040	SFAS 112 Postemployment Benef	1,501,340.51	(1,395,640.63)			707,942.00			
		9260042	SERP Pension - Non-Service			11,382.84	11,382.84	9,045.57	10,603.76	10,603.76	10,603.76
		9260043	OPEB - Non-Service			(685,892.75)	(685,892.75)	(668,275.75)	(680,020.42)	(680,020.42)	(680,020.42)
		9260050	Frg Ben Loading - Pension	(2,754,805.70)	(2,676,651.61)	(231,162.87)	(259,144.88)	(395,265.97)	(206,254.82)	(216,410.91)	(199,264.12)
		9260051	Frg Ben Loading - Grp Ins	(5,491,155.86)	(5,205,469.61)	(413,885.18)	(465,279.14)	(707,557.06)	(397,111.61)	(418,274.61)	(383,839.42)
		9260052	Frg Ben Loading - Savings	(1,770,243.20)	(1,700,765.38)	(127,837.23)	(146,508.79)	(219,215.31)	(146,943.68)	(154,605.56)	(140,063.35)
		9260053	Frg Ben Loading - OPEB	823,598.03	2,085,173.10	26,033.03	(38,406.85)	(54,721.60)	(54,437.50)	(59,369.21)	(56,273.89)
		9260055	IntercoFringeOffset- Don't Use	(2,519,397.32)	(2,261,541.30)	(177,873.54)	(262,221.41)	(375,757.72)	(241,891.60)	(252,358.37)	(243,637.02)
		9260058	Frg Ben Loading - Accrual	(49,330.25)	11,801.79	(449,500.74)	32,086.04	468,302.72	(80,552.20)	(117,335.97)	(86,125.02)
		9260060	Amort-Post Retirement Benefit	533,310.00	533,310.00	44,442.50	44,442.50	44,442.50	44,442.50	44,442.50	44,442.50
		9260062	Pension Plan - Non-Service			(89,045.59)	(89,045.59)	(103,621.32)	(93,904.17)	(93,904.17)	(93,904.17)
	9260 Total			**16,722,408.64**	**14,899,931.15**	**447,970.97**	**872,146.10**	**1,569,392.30**	**929,872.59**	**797,499.45**	**915,266.84**
9270	**Franchise Requirements**	9270000	Franchise Requirements	154.00							
	9270 Total			**154.00**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
9280	**Regulatory Commission Exp**	9280000	Regulatory Commission Exp	(76.39)	693.39	354.00	121.99	113.20	2,921.71	1.68	(249.91)
		9280001	Regulatory Commission Exp-Adm	36,640.81	37,955.40			5.21	(5.21)		36,705.00
		9280002	Regulatory Commission Exp-Case	5,932,885.36	4,187,109.26	454,142.68	435,038.63	253,639.92	310,078.37	387,910.54	423,902.81
		9280003	Rate Case Amort			-	-	-	-	-	-
		9280005	Reg Com Exp-FERC Trans Cases	6,873.15	71,578.71	4,723.82	4,326.59	11,936.13	13,814.04	12,875.69	17,774.44
	9280 Total			**5,976,322.93**	**4,297,336.76**	**459,220.50**	**439,487.21**	**265,694.46**	**326,808.91**	**400,787.91**	**478,132.34**
9301	**General Advertising Expenses**	9301000	General Advertising Expenses	114,496.79	35,002.88	53,098.64	5,004.55	6,117.32	642.09	2,693.23	3,704.43
		9301001	Newspaper Advertising Space	21,729.14	31,948.82	701.00	200.59	6,695.01	443.74	2,380.00	738.72
		9301002	Radio Station Advertising Time	11,144.86	7,279.81	400.00	399.97	900.01	4,999.97	400.01	1,837.50
		9301003	TV Station Advertising Time	13,765.02							
		9301010	Publicity	5,164.52	2,001.15		92.50		37.87	345.24	403.00
		9301012	Public Opinion Surveys	58,022.45	60,297.84	2,906.89	2,838.22	7,937.60	2,144.22	1,567.64	7,729.78
		9301015	Other Corporate Comm Exp	53,303.58	56,381.82	6,555.78	3,469.26	9,066.61	7,846.12	3,484.61	7,755.19

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FERC	FERC Title	Account	Description	YTD 12/31/2016	YTD 12/31/2017	1/31/2018	2/28/2018	3/31/2018	4/30/2018	5/31/2018	6/30/2018
	9301 Total			**277,626.36**	**192,912.32**	**63,662.31**	**12,005.09**	**30,716.55**	**16,114.01**	**10,870.73**	**22,168.62**
9302	**Misc General Expenses**	9302000	Misc General Expenses	648,215.68	595,787.08	399,555.21	56,011.27	36,320.25	30,868.69	27,686.50	26,814.61
		9302003	Corporate & Fiscal Expenses	85,474.18	27,663.03	10,582.15	11,448.22	11,101.61	8,652.66	7,751.80	(1,812.26)
		9302004	Research, Develop&Demonstr Exp	1,952.44	370.86	1,999.65	(456.15)	(88.79)	568.06	57.78	79.99
		9302006	Assoc Bus Dev - Materials Sold	45,480.95	196,759.82	1,093.34	1,164.24	457.02	5,314.06	11,538.66	2,497.54
		9302007	Assoc Business Development Exp	581,271.38	285,789.62	24,686.27	29,574.79	29,132.30	20,232.48	59,303.17	31,885.35
	9302 Total			**1,362,394.63**	**1,106,370.41**	**437,916.62**	**97,742.37**	**76,922.39**	**65,635.95**	**106,337.91**	**59,465.24**
9310	**Rents**	9310000	Rents	144,743.80	144,732.00	12,061.00	12,061.00			14.51	
		9310001	Rents - Real Property	207,629.06	218,426.56	14,922.10	18,291.56	18,239.37	18,602.65	17,847.65	18,304.78
		9310002	Rents - Personal Property	837,655.22	563,538.57	55,995.76	49,198.38	46,945.33	46,294.67	45,776.27	48,111.88
	9310 Total			**1,190,028.08**	**926,697.13**	**82,978.86**	**79,550.94**	**65,184.70**	**64,897.32**	**63,638.43**	**66,416.66**
9350	**Maintenance of General Plant**	9350000	Maintenance of General Plant		215.64	(10.87)	11.43	(10.84)	(0.59)	112.80	215.91
		9350001	Maint of Structures - Owned	1,802,173.54	1,818,148.89	81,789.40	123,016.42	122,261.90	62,591.30	145,728.95	141,196.50
		9350002	Maint of Structures - Leased	6,546.27	5,590.39	1,942.46	(3,661.36)	(54.95)	115.51	1,894.26	(519.36)
		9350012	Maint of Data Equipment	597,344.99	(69,159.92)	1,953.16	1,953.31	1,989.05	1,982.37	1,973.73	1,967.07
		9350013	Maint of Cmmncation Eq-Unall	3,495,280.62	2,721,519.06	277,777.47	162,222.56	172,542.44	251,691.34	247,231.72	183,913.68
		9350014	Maint Supv & Eng-Cmmun Eq							9.58	(9.58)
		9350015	Maint of Office Furniture & Eq	2,588,959.64	2,671,435.53	464,705.87	267,564.38	246,690.77	340,242.87	108,615.80	197,486.49
		9350019	Maint of Gen Plant-SCADA Equ	745.86	1,096.79	122.07	273.78	271.02	267.21	261.07	252.23
		9350024	Maint of DA-AMI Comm Equip	11,167.54	8,386.63	64.64	703.46	(783.93)	117.68	120.50	73.29
	9350 Total			**8,502,218.46**	**7,157,233.01**	**828,344.20**	**552,083.98**	**542,905.46**	**657,007.69**	**505,948.41**	**524,576.23**
4010	**Operation Expense**	4010001	Operation Exp - Nonassociated				2,797.84	(1,802.20)	(70.21)	2,360.39	2,292.81
	4010 Total			**-**	**-**	**-**	**2,797.84**	**(1,802.20)**	**(70.21)**	**2,360.39**	**2,292.81**
4030	**Depreciation Expense**	4030001	Depreciation Exp	189,672,527.07	205,525,406.10	17,610,764.09	17,654,301.38	17,688,405.26	17,753,691.84	17,767,851.45	17,583,602.35
		4030028	Depreciation Expense Deferred	(2,693,039.00)	(1,682,793.38)	206,953.44	130,021.91	(5,746.67)	(5,634.23)	261,502.61	446,817.93
	4030 Total			**186,979,488.07**	**203,842,612.72**	**17,817,717.53**	**17,784,323.29**	**17,682,658.59**	**17,748,057.61**	**18,029,354.06**	**18,030,420.28**
4031	**Depr - Asset Retirement Oblig**	4031001	Depr - Asset Retirement Oblig	1,361,093.43	1,523,744.10	123,073.50	123,073.49	123,073.55	123,073.50	123,073.48	123,073.55
	4031 Total			**1,361,093.43**	**1,523,744.10**	**123,073.50**	**123,073.49**	**123,073.55**	**123,073.50**	**123,073.48**	**123,073.55**
4037	**Depreciation Expense**	4037000	Amort-TX Cap Impairment	(1,130,962.20)	(1,130,962.20)	(121,889.79)	(121,889.79)	(121,889.79)	(121,889.79)	(121,889.79)	(121,889.79)
		4037001	Amort TX SERP			(1,044.62)	(994.11)	(993.35)	(993.35)	(992.80)	(992.22)
		4037002	Amort TX RWIP Cap Incen			(458.41)	(457.74)	(460.73)	(462.85)	(467.00)	(465.81)
		4037003	Amort TX CWIP Cap Incent			(12,012.38)	(11,705.72)	(11,818.90)	(11,901.03)	(12,009.89)	(12,064.29)
		4037004	Amort TX Cap Veg Mgmt Costs			(11,034.38)	(11,042.52)	(11,079.24)	(11,166.83)	(11,224.62)	(11,307.17)
	4037 Total			**(1,130,962.20)**	**(1,130,962.20)**	**(146,439.58)**	**(146,089.88)**	**(146,242.01)**	**(146,413.85)**	**(146,584.10)**	**(146,719.28)**
4040	**Amortization of Plant**	4040001	Amort. of Plant	9,314,572.96	12,959,003.51	1,323,426.71	1,342,862.07	1,405,762.11	1,380,475.59	1,399,502.38	1,421,125.15
	4040 Total			**9,314,572.96**	**12,959,003.51**	**1,323,426.71**	**1,342,862.07**	**1,405,762.11**	**1,380,475.59**	**1,399,502.38**	**1,421,125.15**
4073	**Regulatory Debits**	4073000	Regulatory Debits							272,033.55	272,033.55
		4073016	Welsh Unit 2 Reg Asset Amort		279,437.02	40,298.22	40,393.55	40,489.11	40,584.90	40,680.91	40,777.15
		4073017	Welsh U2 ARO Reg Asset Amort		4,383.06	593.34	593.34	593.34	593.34	593.34	593.34
	4073 Total			**-**	**283,820.08**	**40,891.56**	**40,986.89**	**41,082.45**	**41,178.24**	**313,307.80**	**313,404.04**
4074	**Regulatory Credits**	4074000	Regulatory Credits	(72,000.00)	(72,000.00)	(6,000.00)	(6,000.00)	(6,000.00)	(6,000.00)	(6,000.00)	(6,000.00)
	4074 Total			**(72,000.00)**	**(72,000.00)**	**(6,000.00)**	**(6,000.00)**	**(6,000.00)**	**(6,000.00)**	**(6,000.00)**	**(6,000.00)**
4081	**Taxes Other Than Inc Tax, UOI**	4081002	FICA	9,769,094.55	9,696,274.78	865,266.75	862,288.57	860,028.68	912,408.35	930,505.21	844,314.82
		4081003	Federal Unemployment Tax	65,411.85	63,660.87	30,654.16	(128.62)	787.07	377.86	310.60	565.14
		40810051	Real Personal Property Taxes	(560,748.44)							
		40810051	Real Personal Property Taxes	53,183,368.54	64,607.94						
		40810051	Real Personal Property Taxes		60,912,656.55	10,459.70	(556,162.88)	(18,711.90)	10,459.70	10,459.70	10,459.70
		40810051	Real Personal Property Taxes			5,406,965.00	5,406,965.00	5,406,965.00	5,406,965.00	5,406,965.00	4,507,853.33
		40810061	State Gross Receipts Tax	2.00							
		40810061	State Gross Receipts Tax	5,739,232.45	2.00						
		40810061	State Gross Receipts Tax		5,722,638.38		2.00				
		40810061	State Gross Receipts Tax			449,532.94	449,532.94	449,532.94	499,479.24	499,481.25	499,479.25

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		4081007	State Unemployment Tax	104,569.53	110,561.48	27,834.40	(1,818.85)	1,006.92	430.03	288.77	540.18
		40810081	State Franchise Taxes	(825.00)							
		40810081	State Franchise Taxes	4,673,698.18	(825.00)						
		40810081	State Franchise Taxes		5,586,359.25	1,404,100.00			27,850.96	1,167,000.00	
		40810141	Federal Excise Taxes	94.32							
		40810141	Federal Excise Taxes	5,029.40							
		40810141	Federal Excise Taxes		6,578.71	517.92					
		40810141	Federal Excise Taxes								
		40810171	St Lic-Rgstrtion Tax-Fees	24,200.00	300.00						
		40810171	St Lic-Rgstrtion Tax-Fees		200.00		14,275.00			300.00	
		40810171	St Lic-Rgstrtion Tax-Fees				17,060.00		10.00		
		40810181	St Publ Serv Comm Tax-Fees	724,626.27							
		40810181	St Publ Serv Comm Tax-Fees	1,183,165.88	762,515.69						
		40810181	St Publ Serv Comm Tax-Fees		1,191,212.57	119,721.00	119,721.00	132,519.61	119,721.00	119,721.00	119,721.00
		40810181	St Publ Serv Comm Tax-Fees			42,000.00	42,000.00	42,000.00	40,000.00	40,000.00	44,992.72
		40810190	State Sales and Use Taxes		311,500.00		14,000.00	(325,500.00)			
		40810191	State Sales and Use Taxes	43,666.74							
		40810191	State Sales and Use Taxes	443.68							
		40810191	State Sales and Use Taxes	(3,105.99)	(586.16)			185,276.61	(0.01)		
		40810191	State Sales and Use Taxes		602.20	245.80					
		40810191	State Sales and Use Taxes				(160.86)	(0.02)	1.34	0.02	35.33
		40810221	Municipal License Fees	81,300.00							
		40810221	Municipal License Fees		80,250.00						
		40810221	Municipal License Fees			80,475.00					
		40810231	Local Privilege-Franchise Tax	16,796,862.82							
		40810231	Local Privilege-Franchise Tax		16,727,761.89						
		40810231	Local Privilege-Franchise Tax			1,636,698.80	1,374,119.95	1,199,142.73	1,185,476.98	1,292,748.55	1,750,611.98
		40810271	Misc State and Local Taxes	20.00							
		40810291	Real-Pers Prop Tax-Cap Leases	(6,959.18)							
		40810291	Real-Pers Prop Tax-Cap Leases	145,000.00	(8,546.84)						
		40810291	Real-Pers Prop Tax-Cap Leases		145,183.00		9,468.86				
		40810291	Real-Pers Prop Tax-Cap Leases			14,417.00	14,417.00	14,417.00	14,417.00	14,417.00	14,417.00
		4081033	Fringe Benefit Loading - FICA	(3,065,410.10)	(3,068,798.81)	(226,313.32)	(261,042.79)	(387,312.72)	(257,524.77)	(287,559.91)	(249,545.82)
		4081034	Fringe Benefit Loading - FUT	(19,284.91)	(23,614.54)	(1,346.48)	(1,453.23)	(2,308.60)	(1,571.57)	(1,668.01)	(1,610.51)
		4081035	Fringe Benefit Loading - SUT	(33,455.48)	(33,340.44)	(2,424.38)	(2,678.37)	(4,178.81)	(1,678.34)	(1,683.57)	(1,679.90)
	4081 Total			**88,849,997.11**	**98,247,153.52**	**9,858,804.29**	**7,500,404.72**	**7,553,664.51**	**7,956,822.77**	**9,191,285.61**	**7,540,154.22**
4082	**Real Personal Property Taxes**	40820051	Real Personal Property Taxes	11,517.51							
		40820051	Real Personal Property Taxes		11,516.34						
	4082 Total			**11,517.51**	**11,516.34**	**-**	**-**	**-**	**-**	**-**	**-**
4091	**Income Taxes, Utility Oper Inc**	4091001	Income Taxes, UOI - Federal	(99,878,779.87)	(32,170,425.49)	3,146,330.36	1,088,549.48	(39,213.28)	2,092,297.64	4,628,566.60	2,254,236.82
		40910020	Income Taxes, UOI - State		353.35						
		40910021	Income Taxes UOI - State	(2,331,852.28)							
		40910021	Income Taxes UOI - State	(10,323,816.42)	(1,445,931.49)						
		40910021	Income Taxes UOI - State		870,042.59						
		40910021	Income Taxes UOI - State			877,754.02	235,843.76	(214,898.53)	56,872.89	1,617,714.68	(386,197.26)
	4091 Total			**(112,534,448.57)**	**(32,745,961.04)**	**4,024,084.38**	**1,324,393.24**	**(254,111.81)**	**2,149,170.53**	**6,246,281.28**	**1,868,039.56**
4092	**Income Tax, Oth Inc & Ded**	4092001	Inc Tax, Oth Inc&Ded-Federal	(107,302.22)	(2,259,644.56)	(602,811.23)	(502,549.93)	(890,460.28)	(909,177.49)	(910,845.63)	(1,772,243.05)
		40920021	Inc Tax Oth Inc Ded - State	(20,283.80)							
		40920021	Inc Tax Oth Inc Ded - State	131,422.34	(15,529.12)						
		40920021	Inc Tax Oth Inc Ded - State		(294,992.71)						
		40920021	Inc Tax Oth Inc Ded - State			(137,824.78)	(114,901.39)	(203,591.99)	(207,871.36)	(208,252.82)	(243,325.03)
	4092 Total			**3,836.32**	**(2,570,166.39)**	**(740,636.01)**	**(617,451.32)**	**(1,094,052.27)**	**(1,117,048.85)**	**(1,119,098.45)**	**(2,015,568.08)**
4101	**Prov Def Inc Tax, Util Oper In**	4101001	Prov Def I/T Util Op Inc-Fed	315,328,109.50	229,402,519.82	703,586,966.30	3,116,732.19	40,529,528.42	2,986,929.22	3,311,950.85	11,725,546.81
		4101002	Prov Def I/T Util Op Inc-State	3,004,116.71	4,657,645.61						1,825,929.73
	4101 Total			**318,332,226.21**	**234,060,165.43**	**703,586,966.30**	**3,116,732.19**	**40,529,528.42**	**2,986,929.22**	**3,311,950.85**	**13,551,476.54**
4102	**Prov Def I/T Oth Inc & Ded**	4102001	Prov Def I/T Oth I&D - Federal	122,036.25	3,770,333.67	1,214,486.54	135,030.00	135,030.00	135,030.00	135,030.00	135,030.00
	4102 Total			**122,036.25**	**3,770,333.67**	**1,214,486.54**	**135,030.00**	**135,030.00**	**135,030.00**	**135,030.00**	**135,030.00**

Southerwestern Electric Power Company
Trial Balance - Income Statement
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

FERC	FERC Title	Account	Description	YTD 12/31/2016	YTD 12/31/2017	1/31/2018	2/28/2018	3/31/2018	4/30/2018	5/31/2018	6/30/2018
4111	**Prov Def I/T-Cr Util Oper Inc**	4111001	Prv Def I/T-Cr Util Op Inc-Fed	(139,085,862.10)	(133,490,542.95)	(703,825,461.67)	(3,377,653.11)	(39,407,906.51)	(4,193,927.90)	(4,188,046.68)	(12,443,289.57)
		4111002	Prv Def I/T-Cr UtilOpInc-State	(13,024,252.97)	(8,925,283.67)			(1,395,115.83)			
		4111005	Accretion Expense	2,508,139.91	2,588,638.65	219,291.60	220,283.03	220,975.08	221,712.94	222,371.41	222,889.80
	4111 Total			**(149,601,975.16)**	**(139,827,187.97)**	**(703,606,170.07)**	**(3,157,370.08)**	**(40,582,047.26)**	**(3,972,214.96)**	**(3,965,675.27)**	**(12,220,399.77)**
4112	**Prv Def I/T-Cr Oth I&D**	4112001	Prv Def I/T-Cr Oth I&D-Fed	(2,684,727.19)	(2,713,154.84)	(1,079,456.55)					
	4112 Total			**(2,684,727.19)**	**(2,713,154.84)**	**(1,079,456.55)**	**-**	**-**	**-**	**-**	**-**
4114	**ITC Adj, Utility Operations**	4114001	ITC Adj, Utility Oper - Fed	(1,207,659.00)	(1,364,974.00)	(118,518.00)	(118,518.00)	(118,518.00)	(118,518.00)	(118,518.00)	(118,518.00)
	4114 Total			**(1,207,659.00)**	**(1,364,974.00)**	**(118,518.00)**	**(118,518.00)**	**(118,518.00)**	**(118,518.00)**	**(118,518.00)**	**(118,518.00)**
4116	**Gain From Disposition of Plant**	4116000	Gain From Disposition of Plant		(8,490,262.75)		627,387.95				(8,176.21)
	4116 Total			**-**	**(8,490,262.75)**	**-**	**627,387.95**	**-**	**-**	**-**	**(8,176.21)**
4118	**Gain Disposition of Allowances**	4118002	Comp. Allow Gains Title IV SO2	(87.23)	(82.10)					(84.45)	
		4118006	CSAPR SO2 Gains	(9,900.00)							
		4118008	Comp Allow Gain CSAPR Seas NOx	(235,500.00)							
		4118009	Comp Allow Gains CSAPR An NOx	(3,482.65)							
	4118 Total			**(248,969.88)**	**(82.10)**	**-**	**-**	**-**	**-**	**(84.45)**	**-**
4180	**Non-Operatng Rental Income**	4180001	Non-Operatng Rental Income	(324,273.06)	(355,245.01)		(121.07)				(113.49)
		4180003	Non-Opratng Rntal Inc-Maint	14,624.18	11,701.00						
	4180 Total			**(309,648.88)**	**(343,544.01)**	**-**	**(121.07)**	**-**	**-**	**-**	**(113.49)**
4181	**Equity Erngs of Subsidiary Co**	4181001	Equity Erngs of Sub-Consolidat	(10,520.38)	(16,651.24)	(1,078.48)	(2,168.16)	(2,746.77)	(3,209.80)	(2,973.76)	(2,899.27)
		4181002	Equity Erngs of Sub-Nonconsol	(7,949,651.06)	3,834,185.91	(213,436.93)	(170,786.98)	(147,950.87)	(150,009.70)	(200,190.52)	(289,643.02)
	4181 Total			**(7,960,171.44)**	**3,817,534.67**	**(214,515.41)**	**(172,955.14)**	**(150,697.64)**	**(153,219.50)**	**(203,164.28)**	**(292,542.29)**
4190	**Interest & Dividend Income**	4190002	Int & Dividend Inc - Nonassoc	(856,656.12)	(2,607,194.05)	(228,401.97)	(1,017,825.77)	(5,388.90)	(198,554.44)	(209,310.37)	(177,682.68)
		4190005	Interest Income - Assoc CBP	(620,813.42)	(83,400.84)	(133,179.01)	(395,410.01)	(12,197.30)			
	4190 Total			**(1,477,469.54)**	**(2,690,594.89)**	**(361,580.98)**	**(1,413,235.78)**	**(17,586.20)**	**(198,554.44)**	**(209,310.37)**	**(177,682.68)**
4191	**Allw Oth Fnds Usd Drng Cnstr**	4191000	Allw Oth Fnds Usd Drng Cnstr	(11,002,400.12)	(2,438,443.68)	(527,104.10)	(882,475.57)	(858,300.88)	(429,003.80)	(358,799.30)	(137,450.58)
	4191 Total			**(11,002,400.12)**	**(2,438,443.68)**	**(527,104.10)**	**(882,475.57)**	**(858,300.88)**	**(429,003.80)**	**(358,799.30)**	**(137,450.58)**
4210	**Misc Non-Operating Income**	4210002	Misc Non-Op Inc-NonAsc-Rents	(2,779.66)	(2,736.81)	(200.82)	(203.39)	(203.59)	(201.97)	(202.46)	(528.14)
		4210003	Misc Non-Op Inc-NonAscRoylty	(3,608.49)	(5,443.96)						
		4210005	Misc Non-Op Inc-NonAsc-Timber	(59,030.82)	(42,146.25)						
		4210007	Misc Non-Op Inc - NonAsc - Oth	(605,365.10)	(671,074.64)	(30,084.67)	(98,479.88)	(27,387.91)	(29,982.62)	(84,854.27)	(28,803.08)
		4210009	Misc Non-Op Exp - NonAssoc	9,821.96	3,053.56	2,279.16	226.48	(1,284.85)	700.49	881.42	710.00
	4210 Total			**(660,962.11)**	**(718,348.10)**	**(28,006.33)**	**(98,456.79)**	**(28,876.35)**	**(29,484.10)**	**(84,175.31)**	**(28,621.22)**
4211	**Gain on Dspsition of Property**	4211000	Gain on Dspsition of Property	(93,628.06)							
	4211 Total			**(93,628.06)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
4212	**Loss on Dspsition of Property**	4212000	Loss on Dspsition of Property	32,590.18	10,348.92						
	4212 Total			**32,590.18**	**10,348.92**	**-**	**-**	**-**	**-**	**-**	**-**
4261	**Donations**	4261000	Donations	7,321,974.10	327,046.93	37,011.63	63,793.91	52,316.33	35,223.95	17,430.25	21,140.84
	4261 Total			**7,321,974.10**	**327,046.93**	**37,011.63**	**63,793.91**	**52,316.33**	**35,223.95**	**17,430.25**	**21,140.84**
4263	**Penalties**	4263001	Penalties	78,757.58	2,479.39	72,780.60			(128.76)	52.34	(10.45)
		4263003	Penalties - Quality of Service	179,834.00	16,721.32		2,777.77				111,411.50
	4263 Total			**258,591.58**	**19,200.71**	**72,780.60**	**2,777.77**	**-**	**(128.76)**	**52.34**	**111,401.05**
4264	**Civic & Political Activities**	4264000	Civic and Political Activity	946,018.99	870,005.58	128,709.66	63,483.02	74,283.67	64,052.21	63,738.39	76,757.63
		4264001	Non-deduct Lobbying per IRS		9,556.77	74.57			169.21	13,357.14	12,885.93
	4264 Total			**946,018.99**	**879,562.35**	**128,784.23**	**63,483.02**	**74,283.67**	**64,221.42**	**77,095.53**	**89,643.56**
4265	**Other Deductions**	4265001	Other Deductions - Associated			-	-	-	-	-	-
		4265002	Other Deductions - Nonassoc	201,632.58	33,724,226.72	137,757.57	79,803.73	61,533.95	82,353.68	49,363.60	92,218.03
		4265004	Social & Service Club Dues	106,286.41	51,146.99	13,743.12	4,664.52	18,657.34	6,156.30	5,523.43	4,145.38
		4265006	Shutdown Coal Company Exp			-	-	-	-	-	-

Southerwestern Electric Power Company
Trial Balance - Income Statement
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

FERC	FERC Title	Account	Description	YTD 12/31/2016	YTD 12/31/2017	1/31/2018	2/28/2018	3/31/2018	4/30/2018	5/31/2018	6/30/2018
		4265007	Regulatory Expenses	32,393.85	25,182.41	7,511.13	2,609.72	205.50	5,011.06		2,507.05
		4265009	Factored Cust A/R Exp - Affil	3,275,236.16	3,805,681.78	346,832.53	411,915.56	374,613.50	342,953.11	434,376.46	452,036.53
		4265010	Fact Cust A/R-Bad Debts-Affil	3,639,704.68	3,386,234.30	315,020.62	246,835.61	224,368.18	227,535.31	270,867.85	335,200.58
		4265033	Transition Costs		277.77	82.39	53.72	327.95			
		4265038	Wind Catcher Project Expenses		9,612,193.65	2,638,009.87	3,201,748.38	3,689,962.38	3,972,176.34	4,089,285.92	4,615,699.77
	4265 Total			**7,255,253.68**	**50,604,943.62**	**3,458,957.23**	**3,947,631.24**	**4,369,668.80**	**4,636,185.80**	**4,849,417.26**	**5,501,807.34**
4270	**Interest on Long -Term Debt**	4270002	Int on LTD - Install Pur Contr	4,900,150.00	4,900,150.00	408,345.83	408,345.83	125,346.11	71,333.34	71,333.33	71,333.34
		4270005	Int on LTD - Other LTD	2,218,020.30	2,609,594.80	289,620.60	261,592.80	295,693.75	310,643.76	323,448.19	321,142.29
		4270006	Int on LTD - Sen Unsec Notes	109,832,571.58	104,239,736.48	9,074,804.41	10,085,429.39	8,616,677.98	8,616,679.42	8,616,679.40	8,616,679.45
	4270 Total			**116,950,741.89**	**111,749,481.28**	**9,772,770.84**	**10,755,368.02**	**9,037,717.84**	**8,998,656.52**	**9,011,460.92**	**9,009,155.08**
4280	**Amrtz Debt Dscnt & Exp**	4280002	Amrtz Debt Dscnt&Exp-Instl Pur	526,290.23	466,143.60	28,750.62	28,052.84	2,804.65	2,804.65	2,804.65	2,804.65
		4280003	Amrtz Debt Dscnt&Exp-N/P		2,676.58						
		4280006	Amrtz Dscnt&Exp-Sn Unsec Note	1,676,686.91	1,683,464.82	155,049.87	155,049.78	128,879.97	128,910.29	129,592.88	129,592.88
	4280 Total			**2,202,977.14**	**2,152,285.00**	**183,800.49**	**183,102.62**	**131,684.62**	**131,714.94**	**132,397.53**	**132,397.53**
4281	**Amrtz Loss on Reacquird Debt**	4281001	Amrtz Loss Rcquired Debt-FMB	206,501.40	206,501.40	17,208.45	17,208.45	17,208.45	17,208.45	17,208.44	17,208.45
		4281002	Amrtz LossRcquired Debt-IPC	297,114.96	297,114.96	24,759.58	24,759.98	4,088.56	4,088.56	4,088.56	4,088.56
		4281004	Amrtz Loss Rcquired Debt-Dbnt	232,270.06	235,883.63	19,656.97	19,656.97	19,656.97	19,656.97	19,656.96	19,656.97
	4281 Total			**735,886.42**	**739,499.99**	**61,625.00**	**61,625.40**	**40,953.98**	**40,953.98**	**40,953.96**	**40,953.98**
4291	**Amrtz Gain Rcqred Debt-Cr**	4291001	Amrtz Gain Rcqred Debt-Cr-FMB	(11,111.52)	(11,111.52)	(925.96)	(925.96)	(925.96)	(925.96)	(925.95)	(925.96)
	4291 Total			**(11,111.52)**	**(11,111.52)**	**(925.96)**	**(925.96)**	**(925.96)**	**(925.96)**	**(925.95)**	**(925.96)**
4300	**Int to Associated Companies**	4300003	Int to Assoc Co - CBP	1,025,986.87	1,173,399.75	166,969.90		268,190.91	366,667.01	398,089.73	327,174.83
	4300 Total			**1,025,986.87**	**1,173,399.75**	**166,969.90**	**-**	**268,190.91**	**366,667.01**	**398,089.73**	**327,174.83**
4310	**Other Interest Expense**	4310001	Other Interest Expense	(4,846,947.12)	(1,391,886.97)	88,823.10	(9,543.00)	98,768.10	88,634.89	103,021.89	392,602.26
		4310002	Interest on Customer Deposits	1,676,329.49	1,729,383.07	153,816.41	138,739.66	154,605.34	151,023.12	156,505.12	154,975.39
		4310007	Lines Of Credit	687,453.50	558,759.85	51,989.08	46,429.47	50,973.08	51,649.42	46,323.63	46,972.49
		4310014	Other Interest - Fuel Recovery	78,738.32		-	-	-	-	-	-
		4310017	Mine Reclamation Interest	1,838,172.66	2,024,923.12	177,739.60	179,172.75	180,607.74	182,052.29	183,518.76	185,011.88
		4310023	Interest Expense - State Tax	(1,475,452.55)	(9,876.71)			2,187.00			88,473.00
	4310 Total			**(2,041,705.71)**	**2,911,302.36**	**472,368.19**	**354,798.88**	**487,141.26**	**473,359.72**	**489,369.40**	**868,035.02**
4320	**Allw Brrwed Fnds Used Cnstr-Cr**	4320000	Allw Brrwed Fnds Used Cnstr-Cr	(6,894,200.65)	(2,095,189.16)	(389,410.24)	(479,361.20)	(516,885.75)	(507,568.39)	(502,920.86)	(460,435.63)
	4320 Total			**(6,894,200.65)**	**(2,095,189.16)**	**(389,410.24)**	**(479,361.20)**	**(516,885.75)**	**(507,568.39)**	**(502,920.86)**	**(460,435.63)**
	Net (Income)/Loss			**(165,555,916.75)**	**(124,685,580.40)**	**(12,086,798.18)**	**(1,826,103.26)**	**2,135,451.06**	**280,611.08**	**(26,396,651.70)**	**(11,546,678.49)**

Southerwestern Electric Power Company
Trial Balance - Income Statement
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger sub fiscal or calendar years. Also, provide monthly trial balances fo

FERC	FERC Title	Account	Description	7/31/2018	8/31/2018	9/30/2018	10/31/2018	11/30/2018	12/31/2018	Test Year Total
4400	**Residential Sales**	4400001	Residential Sales-W/Space Htg	(11,925,261.96)	(12,923,915.00)	(11,353,875.00)	(7,259,703.00)	(5,165,314.00)	(8,711,964.00)	(111,073,810.76)
		4400002	Residential Sales-W/O Space Ht	(44,536,777.05)	(41,753,154.00)	(36,680,844.00)	(23,453,845.00)	(16,687,525.00)	(28,145,648.00)	(358,844,977.42)
		4400005	Residential Fuel Rev	(23,938,135.44)	(21,478,101.00)	(16,816,190.00)	(12,217,971.00)	(10,675,481.00)	(16,290,621.00)	(196,922,958.23)
		4400006	Residential O/U Fuel Rev	796,593.38	-	(2,445.00)	(18,216.00)	3,575.00	(19,124.00)	(1,399,949.76)
	4400 Total			**(79,603,581.07)**	**(76,155,170.00)**	**(64,853,354.00)**	**(42,949,735.00)**	**(32,524,745.00)**	**(53,167,357.00)**	**(668,241,696.17)**
										-
4420	**Commercial & Industrial Sales**	4420001	Commercial Sales	(24,607,669.17)	(31,755,999.00)	(30,890,620.00)	(25,000,408.00)	(26,724,957.00)	(27,065,657.00)	(294,667,899.87)
		4420002	Industrial Sales (Excl Mines)	(15,950,180.03)	(12,436,596.00)	(11,939,967.00)	(10,487,638.00)	(11,415,410.00)	(10,946,665.00)	(165,419,443.55)
		4420006	Sales to Pub Auth - Schools	(793,257.84)	(538,150.00)	(516,660.00)	(453,816.00)	(493,962.00)	(473,679.00)	(7,157,947.20)
		4420007	Sales to Pub Auth - Ex Schools	(5,528,998.01)	(4,045,607.00)	(3,884,054.00)	(3,411,614.00)	(3,713,417.00)	(3,560,934.00)	(53,810,707.36)
		4420013	Commercial Fuel Rev	(19,656,645.25)	(17,770,296.00)	(15,825,070.00)	(14,581,936.00)	(14,155,130.00)	(13,635,990.00)	(183,995,343.11)
		4420014	Commercial O/U Fuel Rev	693,821.43	-	34,198.00	12,283.00	20,918.00	17,957.00	(1,382,303.47)
		4420016	Industrial Fuel Rev	(14,841,267.78)	(14,020,151.00)	(12,756,665.00)	(13,732,247.00)	(13,967,780.00)	(12,188,775.00)	(159,926,572.10)
		4420017	Industrial O/U Fuel Rev	783,968.02	-	(39,612.00)	(37,940.00)	(55,246.00)	(90,708.00)	(1,560,061.41)
	4420 Total			**(79,900,228.63)**	**(80,566,799.00)**	**(75,818,450.00)**	**(67,693,316.00)**	**(70,504,984.00)**	**(67,944,451.00)**	**(867,920,278.07)**
										-
4440	**Public Street/Highway Lighting**	4440000	Public Street/Highway Lighting	(531,920.06)	(498,673.00)	(473,988.00)	(494,378.00)	(552,387.00)	(506,025.00)	(6,280,140.73)
		4440002	Public St & Hwy Light Fuel Rev	(219,281.28)	(200,006.00)	(177,706.00)	(205,655.00)	(219,859.00)	(184,533.00)	(2,461,819.28)
		4440003	Pb St & Hwy Light O/U Fuel Rev	8,002.81	-	(890.00)	(1,092.00)	(943.00)	(913.00)	(15,530.46)
	4440 Total			**(743,198.53)**	**(698,679.00)**	**(652,584.00)**	**(701,125.00)**	**(773,189.00)**	**(691,471.00)**	**(8,757,490.47)**
										-
4470	**Sales for Resale**	4470001	Sales for Resale - Assoc Cos	(32,144.79)	-	-	-	-	-	87,843.72
		4470002	Sales for Resale - NonAssoc	(769,111.60)	(421,631.00)	(534,112.00)	(214,787.00)	(129,392.00)	(797,515.00)	(3,484,802.06)
		4470006	Sales for Resale-Bookout Sales	(147,359.32)	-	-	-	-	-	(1,078,635.08)
		4470010	Sales for Resale-Bookout Purch	117,758.11	-	-	-	-	-	820,665.33
		4470027	Whsal/Muni/Pb Ath Fuel Rev	(6,292,404.67)	(6,609,745.00)	(5,797,181.00)	(4,713,846.00)	(4,280,935.00)	(4,410,240.00)	(77,110,895.65)
		4470028	Sale/Resale - NA - Fuel Rev	(4,394,763.02)	(1,868,029.00)	(2,100,321.00)	(779,660.00)	(4,169,345.00)	(4,176,856.00)	(41,919,784.35)
		4470032	Capacity Revenue - Affiliated							-
		4470033	Whsal/Muni/Pub Auth Base Rev	(7,184,040.93)	(5,992,694.00)	(7,022,327.00)	(4,758,518.00)	(5,302,447.00)	(6,112,615.00)	(80,072,511.61)
		4470035	Sls for Rsl - Fuel Rev - Assoc							-
		4470036	Sales for Resale- Fuel - ERCOT	(21,687.12)	-	-	-	-	-	(202,184.14)
		4470074	Sale for Resale-Aff-Trnf Price	-	-	-	-	-	-	-
		4470081	Financial Spark Gas - Realized							-
		4470082	Financial Electric Realized							-
		4470131	Non-Trading Bookout Purch-OSS	185.65	-	-	-	-	-	(1,942.66)
		4470136	SPP Rev Neutrality Ded-Sales	(30,539.18)	-	-	-	-	-	(220,208.35)
		4470150	Transm. Rev.-Dedic. Whlsl/Muni	(533,395.73)	(185,131.00)	(185,131.00)	(185,131.00)	(185,131.00)	(185,131.00)	(3,981,781.30)
		4470175	OSS Sharing Reclass - Retail	(1,215,499.89)	(356,543.00)	(511,944.00)	(221,953.00)	(143,457.00)	(757,480.00)	(9,329,841.83)
		4470176	OSS Sharing Reclass-Reduction	1,215,499.89	356,543.00	511,944.00	221,953.00	143,457.00	757,480.00	9,329,841.83
		4470219	Merchant Fuel Revenue	(1,102,926.06)	-	-	-	-	-	(5,899,836.67)
		4470223	Merchant Sales Margin	(484,272.22)	(385,543.00)	(211,690.00)	(268,125.00)	(272,359.00)	(237,175.00)	(3,717,573.19)
		4470320	SPP Net Regulation OSS	(90,627.78)	-	-	-	-	-	(994,732.76)
		4470321	SPP Net Spinning Reserve OSS	(517,978.10)	-	-	-	-	-	(2,288,909.14)
		4470324	SPP Net Supp Reserve OSS	(12,306.32)	-	-	-	-	-	(27,385.98)
		4470326	SPP Net Marginal Losses OSS	(149,308.68)	-	-	-	-	-	(827,822.25)
		4470328	SPP Net Make Whole Payment OSS	(15,136.61)	-	-	-	-	-	(11,467.62)
		4470332	SPP Congestion Costs OSS	16,255.93	-	-	-	-	-	(2,676,966.68)
	4470 Total			**(21,643,802.44)**	**(15,462,773.00)**	**(15,850,762.00)**	**(10,920,067.00)**	**(14,339,609.00)**	**(15,919,532.00)**	**(223,608,930.44)**
										-
4491	**Provision for Rate Refunds**	4491002	Prov Rate Refund-Nonaffiliated	(1,510,545.90)	-	-	-	-	-	15,831,332.22
		4491003	Prov Rate Refund - Retail	-	-	-	-	-	-	0.11
		4491004	Prov Rate Refund - Affiliated		-	-	-	-	-	-
		4491018	Prov Rate Refund - Tax Reform	4,593,933.02	602,155.00	602,155.00	602,155.00	602,155.00	602,155.00	31,852,371.05
		4491019	Prov Rate Refund-Exces Protect	1,169,169.28	2,630,546.00	1,909,759.00	1,132,915.00	873,932.00	1,012,375.00	15,743,711.92
	4491 Total			**4,252,556.40**	**3,232,701.00**	**2,511,914.00**	**1,735,070.00**	**1,476,087.00**	**1,614,530.00**	**63,427,415.30**
										-
4500	**Forfeited Discounts**	4500000	Forfeited Discounts	(417,475.00)	(545,902.00)	(515,970.00)	(523,350.00)	(373,889.00)	(314,812.00)	(5,032,195.20)
	4500 Total			**(417,475.00)**	**(545,902.00)**	**(515,970.00)**	**(523,350.00)**	**(373,889.00)**	**(314,812.00)**	**(5,032,195.20)**
										-
4510	**Misc Service Revenues**	4510001	Misc Service Rev - Nonaffil	(158,098.41)	(207,755.00)	(228,106.00)	(239,601.00)	(191,407.00)	(161,550.00)	(2,250,904.47)
	4510 Total			**(158,098.41)**	**(207,755.00)**	**(228,106.00)**	**(239,601.00)**	**(191,407.00)**	**(161,550.00)**	**(2,250,904.47)**
										-
4540	**Rent From Electric Property**	4540001	Rent From Elect Property - Af	(121,259.94)	(155,861.00)	(155,861.00)	(155,861.00)	(155,861.00)	(155,861.00)	(1,628,124.58)

Southerwestern Electric Power Company
Trial Balance - Income Statement
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger sub fiscal or calendar years. Also, provide monthly trial balances fo

FERC	FERC Title	Account	Description	7/31/2018	8/31/2018	9/30/2018	10/31/2018	11/30/2018	12/31/2018	Test Year Total
		4540002	Rent From Elect Property-NAC	(284,972.07)	(255,386.00)	(237,811.00)	(265,291.00)	(262,716.00)	(236,042.00)	(3,095,165.23)
		4540004	Rent From Elect Prop-ABD-Nonaf	(2,507.49)	-	-	-	-	-	(22,552.43)
		4540005	Rent from Elec Prop-Pole Attch	(418,633.86)	(391,667.00)	(391,667.00)	(391,666.00)	(391,667.00)	(391,667.00)	(4,823,031.36)
	4540 Total			**(827,373.36)**	**(802,914.00)**	**(785,339.00)**	**(812,818.00)**	**(810,244.00)**	**(783,570.00)**	**(9,568,873.60)**
										-
4560	**Other Electric Revenues**	4560010	Oth Elect Rev - Royalties	(27,963.28)	(26,808.00)	(91,274.00)	(31,531.00)	(17,806.00)	(47,228.00)	(488,963.45)
		4560012	Oth Elect Rev - Nonaffiliated	(143,634.34)	(83,608.00)	(147,362.00)	(158,412.00)	(164,437.00)	(160,888.00)	(1,853,527.39)
		4560013	Oth Elect Rev-Trans-Nonaffil		-	-	-	-	-	(466,408.88)
		4560015	Other Electric Revenues - ABD	(59,210.29)	(56,905.00)	(73,795.00)	(79,425.00)	(79,425.00)	(79,425.00)	(780,171.01)
		4560025	Plant Operations O/H Revenues	(319,828.96)	(333,754.00)	(341,941.00)	(315,128.00)	(204,257.00)	(329,060.00)	(3,207,125.38)
		4560041	Miscellaneous Revenue-NonAffil							-
		4560043	Oth Elec Rv-Trn-Aff-Trnf Price	-	-	-	-	-	-	-
		4560102	Oth Elect Rev-Trans-ERCOT area							-
	4560 Total			**(550,636.87)**	**(501,075.00)**	**(654,372.00)**	**(584,496.00)**	**(465,925.00)**	**(616,601.00)**	**(6,796,196.11)**
										-
4561	**Other Electric Revenues**	4561008	SPP Non-Affil. Base Fundng Rev	(2,871,262.01)	(3,687,277.00)	(3,687,277.00)	(3,687,277.00)	(3,687,277.00)	(3,687,277.00)	(44,598,465.38)
		4561009	SPP Affil. Base Funding Cost	997,961.40	1,478,607.00	1,478,607.00	1,478,607.00	1,478,607.00	1,478,607.00	22,334,934.90
		4561010	SPP Affl. Base Funding Rev	(1,315,536.79)	(1,925,131.00)	(1,925,131.00)	(1,925,131.00)	(1,925,131.00)	(1,925,131.00)	(29,101,095.03)
		4561011	SPP Pt to Pt Trans Serv Rev	(1,437,081.39)	(618,677.00)	(618,677.00)	(618,677.00)	(618,677.00)	(618,677.00)	(8,940,750.65)
		4561012	SPP Direct Assignment	(104,616.77)	(102,751.00)	(102,751.00)	(102,751.00)	(102,751.00)	(102,751.00)	(1,246,072.47)
		4561013	SPP Affiliated NITS Revenue	(10,749,355.58)	(6,911,651.00)	(6,810,167.00)	(6,081,212.00)	(4,555,387.00)	(5,439,342.00)	(80,599,372.16)
		4561014	SPP Ancillary Services	(47,110.76)	(22,810.00)	(21,444.00)	(18,700.00)	(13,141.00)	(22,065.00)	(298,591.01)
		4561015	SPP Ancillary Schedule 1	(141,841.20)	(96,426.00)	(90,650.00)	(79,053.00)	(55,552.00)	(93,275.00)	(1,262,246.07)
		4561016	SPP Affiliated Trans NITS Cost	8,135,728.44	5,052,700.00	5,035,059.00	4,936,563.00	3,661,995.00	4,150,065.00	64,489,076.35
		4561017	Oth Elect Revenues - Ancillary	(70.00)	(70,000.00)	(70,000.00)	(70,000.00)	(70,000.00)	(70,000.00)	(350,490.00)
		4561019	Oth Elec Rev Trans Non Aff							-
		4561020	Oth Elec Rev-Trans-Aff-SPP	-						-
		4561021	SPP NITS	(3,398,944.26)	(2,203,465.00)	(2,072,061.00)	(1,808,273.00)	(1,269,910.00)	(2,112,267.00)	(25,480,554.57)
		4561038	SPP Pt to Pt Trans Affil Cost							-
		4561039	SPP Pt to Pt Trans Affil Rev							-
		4561040	Affil. SPPAncillary Sch.1 Cost	309,943.02	-	-	-	-	-	1,766,633.88
		4561041	Affil. SPPAncillary Sch. 1 Rev	(340,781.28)	-	-	-	-	-	(1,903,763.03)
		4561042	SPP Base Funding Contra		(81,851.00)	(81,851.00)	(81,851.00)	(81,851.00)	(81,851.00)	(409,255.00)
		4561065	Provision RTO Rev-NonAff	-	628,996.00	628,996.00	628,996.00	628,996.00	628,996.00	3,144,980.00
	4561 Total			**(10,962,967.18)**	**(8,559,736.00)**	**(8,337,347.00)**	**(7,428,759.00)**	**(6,610,079.00)**	**(7,894,968.00)**	**(102,455,030.24)**
										-
5000	**Oper Supervision & Engineering**	5000000	Oper Supervision & Engineering	1,698,562.23	1,595,656.00	1,773,862.00	1,639,972.00	1,601,240.00	1,554,518.00	19,276,744.90
		5000001	Oper Super & Eng-RATA-Affil	32,743.39	-	-	-	-	-	116,457.78
	5000 Total			**1,731,305.62**	**1,595,656.00**	**1,773,862.00**	**1,639,972.00**	**1,601,240.00**	**1,554,518.00**	**19,393,202.68**
										-
5010	**Fuel**	5010000	Fuel	349,491.36	335,953.00	335,960.00	340,252.00	340,280.00	335,742.00	4,470,489.67
		5010001	Fuel Consumed	20,443,965.36	18,431,665.00	17,215,059.00	14,239,280.00	17,638,583.00	19,739,767.00	196,682,357.75
		5010003	Fuel - Procure Unload & Handle	1,085,248.98	1,188,158.00	1,087,436.00	939,754.00	1,071,888.00	1,128,164.00	11,182,468.41
		5010005	Fuel - Deferred		-	(470,633.00)	(371,445.00)	(352,001.00)	(435,950.00)	(1,630,029.00)
		5010012	Ash Sales Proceeds	(599,507.15)	(451,392.00)	(426,768.00)	(293,380.00)	(360,367.00)	(271,907.00)	(5,051,812.95)
		5010013	Fuel Survey Activity	(307,097.82)	(100,477.00)	(93,845.00)	(77,623.00)	(96,154.00)	(107,608.00)	(1,072,180.64)
		5010018	Lignite Consumed	17,316,065.18	18,424,649.00	16,768,881.00	15,841,923.00	13,605,611.00	11,189,040.00	182,941,980.87
		5010019	Fuel Oil Consumed	108,568.95	181,198.00	105,212.00	195,411.00	202,134.00	137,947.00	1,996,880.36
		5010020	Nat Gas Consumed Steam	5,906,373.54	3,629,354.00	1,161,566.00	963,747.00	843,251.00	818,474.00	28,725,078.26
		5010021	Transp Gas Consumed Steam	464,229.98	-	-	-	-	-	1,804,266.93
		5010034	Gas Transp Res Fees-Steam	341,229.00	2,500.00	2,500.00	2,500.00	2,500.00	2,500.00	565,490.00
		5010035	Gas Transp Res Fees - CC	529,170.00	529,170.00	512,100.00	529,170.00	512,100.00	529,170.00	6,230,550.00
		5010036	Nat Gas Consumed CC	6,343,438.25	6,006,656.00	5,818,090.00	1,013,100.00	2,671,749.00	7,294,695.00	64,984,010.94
		5010037	Transportation Gas CC	21,390.60	-	-	-	-	-	161,695.80
	5010 Total			**52,002,566.23**	**48,177,434.00**	**42,015,558.00**	**33,322,689.00**	**36,079,574.00**	**40,360,034.00**	**491,991,246.40**
										-
5020	**Steam Expenses**	5020000	Steam Expenses	1,081,600.48	41,410.00	90,066.00	41,410.00	35,237.00	90,060.00	7,739,801.38
		5020001	Lime Expense	130,573.51	344,422.00	335,751.00	321,319.00	358,260.00	384,619.00	2,292,241.41
		5020002	Urea Expense		12,674.00	12,674.00	12,674.00	12,674.00	12,674.00	92,338.48
		5020003	Trona Expense		-	-	-	-	-	-
		5020004	Limestone Expense	435,935.16	417,939.00	400,057.00	407,497.00	348,786.00	296,354.00	4,106,264.94
		5020005	Polymer expense		-	-	-	-	-	1,267.81
		5020006	Consumable Expense-Deferred	(94,388.43)	-	-	-	-	-	(588,182.20)

Southerwestern Electric Power Company
Trial Balance - Income Statement
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger sub fiscal or calendar years. Also, provide monthly trial balances fo

FERC	FERC Title	Account	Description	7/31/2018	8/31/2018	9/30/2018	10/31/2018	11/30/2018	12/31/2018	Test Year Total
		5020007	Lime Hydrate Expense	16,572.93	15,536.00	15,768.00	15,769.00	15,772.00	15,392.00	162,880.60
		5020008	Activated Carbon	438,625.90	440,215.00	425,420.00	424,025.00	376,762.00	320,594.00	4,846,115.96
		5020013	Anhydrous Ammonia Expense	78,718.91	58,766.00	54,572.00	51,376.00	61,943.00	65,654.00	838,931.13
		5020014	Calcium Bromide Expense	23,076.71	17,943.00	17,364.00	17,943.00	13,629.00	9,179.00	182,549.53
		5020016	Dolet Hills Misc Reagents	3,413.06	-	-	-	-	-	21,261.33
		5020025	Steam Exp Environmental	9,836.36	516.00	1,122.00	516.00	439.00	1,122.00	96,434.04
	5020 Total			**2,123,964.59**	**1,349,421.00**	**1,352,794.00**	**1,292,529.00**	**1,223,502.00**	**1,195,648.00**	**19,791,904.41**
										-
5050	**Electric Expenses**	5050000	Electric Expenses	949,039.56	494,883.00	498,842.00	498,893.00	499,013.00	499,444.00	8,701,391.89
	5050 Total			**949,039.56**	**494,883.00**	**498,842.00**	**498,893.00**	**499,013.00**	**499,444.00**	**8,701,391.89**
										-
5060	**Misc Steam Power Expenses**	5060000	Misc Steam Power Expenses	951,290.28	2,436,446.00	2,274,899.00	2,115,320.00	3,265,653.00	2,816,362.00	21,398,788.26
		5060001	Dresden Misc Steam Pwer Exp		-	-	-	-	-	-
		5060003	Removal Cost Expense - Steam	57.36	-	-	-	-	-	(159.12)
	5060 Total			**951,347.64**	**2,436,446.00**	**2,274,899.00**	**2,115,320.00**	**3,265,653.00**	**2,816,362.00**	**21,398,629.14**
										-
5070	**Rents**	5070000	Rents		-	-	-	-	-	-
		5070006	Rents - Associated	267.02	-	-	-	-	-	1,869.14
	5070 Total			**267.02**	**-**	**-**	**-**	**-**	**-**	**1,869.14**
										-
5080	**Operations - Supplies and Expenses**	5080017	IPP Oper - Training/Travel	-	-	-	-	-	-	-
	5080 Total			**-**	**-**	**-**	**-**	**-**	**-**	**-**
										-
5090		5090001	Allowance Consumption - NOx							-
	Allowance Consumption SO2	5090008	Deferred Enviro Emission Costs	22,693.09	-	-	-	-	-	80,107.60
		5090012	CSAPR AN NOx Cons. Exp		-	-	-	-	-	-
		5090013	CSAPR Seasonal NOx Cons. Exp	43,168.47	43,935.00	55,834.00	-	-	-	207,014.77
	5090 Total			**65,861.56**	**43,935.00**	**55,834.00**	**-**	**-**	**-**	**287,122.37**
										-
5100	**Maint Supv & Engineering**	5100000	Maint Supv & Engineering	506,825.81	1,245,459.00	276,905.00	339,038.00	303,203.00	262,552.00	6,094,687.50
		5100001	Dresden Maint Sup& Engineer	39.00	13.00	3.00	4.00	3.00	3.00	65.00
	5100 Total			**506,864.81**	**1,245,472.00**	**276,908.00**	**339,042.00**	**303,206.00**	**262,555.00**	**6,094,752.50**
										-
5110	**Maintenance of Structures**	5110000	Maintenance of Structures	466,463.74	71,573.00	79,906.00	62,521.00	158,517.00	59,066.00	4,093,958.07
	5110 Total			**466,463.74**	**71,573.00**	**79,906.00**	**62,521.00**	**158,517.00**	**59,066.00**	**4,093,958.07**
										-
5120	**Maintenance of Boiler Plant**	5120000	Maintenance of Boiler Plant	2,928,013.59	5,815,766.00	6,480,953.00	6,561,924.00	6,104,317.00	5,902,134.00	53,208,885.25
		5120025	Maint of Blr Plt Environmental	87.53	230.00	256.00	259.00	241.00	233.00	2,102.25
	5120 Total			**2,928,101.12**	**5,815,996.00**	**6,481,209.00**	**6,562,183.00**	**6,104,558.00**	**5,902,367.00**	**53,210,987.50**
										-
5130	**Maintenance of Electric Plant**	5130000	Maintenance of Electric Plant	377,856.07	(39,369.00)	90,429.00	186,445.00	334,087.00	(65,669.00)	6,289,299.44
	5130 Total			**377,856.07**	**(39,369.00)**	**90,429.00**	**186,445.00**	**334,087.00**	**(65,669.00)**	**6,289,299.44**
										-
5140	**Maintenance of Misc Steam Plt**	5140000	Maintenance of Misc Steam Plt	488,807.79	148,872.00	210,891.00	570,128.00	149,840.00	257,996.00	4,979,078.77
	5140 Total			**488,807.79**	**148,872.00**	**210,891.00**	**570,128.00**	**149,840.00**	**257,996.00**	**4,979,078.77**
										-
5460	**Oper Supervision & Engineering**	5460000	Oper Supervision & Engineering	760.77	-	-	-	-	-	8,589.39
	5460 Total			**760.77**	**-**	**-**	**-**	**-**	**-**	**8,589.39**
										-
5470	**Fuel**	5470001	Fuel - Gas Turbine	343,999.68	433,782.00	242,165.00	-	-	-	2,156,163.59
		5470003	Gas Transp Res Fees - CT	829,511.94	1,587,750.00	1,587,750.00	1,587,750.00	1,587,750.00	1,587,750.00	16,565,381.16
		5470005	Gas Transp Fees - CT	83,127.06	-	-	-	-	-	279,775.20
	5470 Total			**1,256,638.68**	**2,021,532.00**	**1,829,915.00**	**1,587,750.00**	**1,587,750.00**	**1,587,750.00**	**19,001,319.95**
										-
5480	**Generation Expenses**	5480000	Generation Expenses	14,699.95	89,215.00	90,098.00	120,099.00	125,116.00	90,054.00	631,161.94
	5480 Total			**14,699.95**	**89,215.00**	**90,098.00**	**120,099.00**	**125,116.00**	**90,054.00**	**631,161.94**
										-
5530	**Maintenance of Generating Plt**	5530001	Maint of Gen Plant - Gas Turb	51,798.78	10,667.00	13,147.00	20,650.00	77,046.00	69,546.00	633,389.83
	5530 Total			**51,798.78**	**10,667.00**	**13,147.00**	**20,650.00**	**77,046.00**	**69,546.00**	**633,389.83**
										-
5540	**Maint of Misc Oth Pwr Gneratn**	5540001	Maint of Oth Pwr Gen Plt-GT	358.49	-	-	-	-	-	16,954.22
	5540 Total			**358.49**	**-**	**-**	**-**	**-**	**-**	**16,954.22**
										-

Southerwestern Electric Power Company
Trial Balance - Income Statement
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger sub fiscal or calendar years. Also, provide monthly trial balances fo

FERC	FERC Title	Account	Description	7/31/2018	8/31/2018	9/30/2018	10/31/2018	11/30/2018	12/31/2018	Test Year Total
5550	**Purchased Power**	5550001	Purch Pwr-NonTrading-Nonassoc	8,319,886.20	6,824,733.00	5,093,122.00	5,520,309.00	2,632,744.00	4,959,964.00	76,906,473.10
		5550003	Purchased Power - Cogeneration	24,698.15	-	-	-	-	-	141,189.33
		5550023	Purch Power Capacity -NA	752,600.12	874,600.00	874,600.00	874,600.00	874,600.00	874,600.00	9,651,203.58
		5550024	Purchase Power ERCOT	(0.01)	-	-	-	-	-	1,003.98
		5550026	Purchase Power - Fuel - ERCOT	51,321.58	-	-	-	-	-	424,021.63
		5550029	Purch Power-Assoc-Trnsfr Price	0.00	-	-	-	-	-	-
		5550032	Gas-Conversion-Mone Plant		-	-	-	-	-	(14.73)
		5550047	Purchase Power Wind Energy	3,057,388.25	4,195,413.00	4,921,763.00	5,265,108.00	6,286,910.00	4,584,380.00	67,480,914.60
		5550054	Purch Power ERCOT-Non-ded	10.15	-	-	-	-	-	(2,409.95)
		5550066	SPP Rev. Neutrality Ded-Purch	313,596.38	-	-	-	-	-	3,202,650.06
		5550113	Cleco PP for Valley - Other							-
		5550128	SPP Net Purch that serve OSS	2,692,965.18	-	-	-	-	-	14,103,215.25
		5550130	SPP Net Marginal Losses LSE	(262,478.12)	400,000.00	250,000.00	250,000.00	250,000.00	250,000.00	4,002,264.98
		5550131	SPP Congestion Costs LSE	604,263.71	1,500,000.00	1,500,000.00	2,500,000.00	2,000,000.00	1,500,000.00	18,223,366.76
		5550133	SPP TCR's & ARR's LSE	(935,588.79)	(1,250,000.00)	(2,000,000.00)	(2,000,000.00)	(1,250,000.00)	(1,500,000.00)	(17,420,056.82)
		5550136	SPP MakeWholePymt Charge Gross	301,725.28	275,000.00	300,000.00	300,000.00	250,000.00	200,000.00	3,541,265.08
		5550138	SPP MakeWholePymt Credit (Net)	(629,181.38)	(150,000.00)	(300,000.00)	(500,000.00)	(300,000.00)	(100,000.00)	(3,547,111.99)
		5550320	SPP Net Regulation LSE	256,699.23	100,000.00	150,000.00	100,000.00	50,000.00	50,000.00	2,061,835.18
		5550321	SPP Net Spinning Reserve LSE	125,799.02	75,000.00	50,000.00	25,000.00	50,000.00	50,000.00	870,413.56
		5550324	SPP Net Supp Reserve LSE	128,130.27	20,000.00	20,000.00	20,000.00	20,000.00	20,000.00	454,825.98
		5550325	SPP Contingency Costs LSE	2,661.67	5,000.00	5,000.00	5,000.00	5,000.00	5,000.00	81,039.94
	5550 Total			**14,804,496.89**	**12,869,746.00**	**10,864,485.00**	**12,360,017.00**	**10,869,254.00**	**10,893,944.00**	**180,176,089.52**
										-
5560	**Sys Control & Load Dispatching**	5560000	Sys Control & Load Dispatching	154,083.29	142,571.00	142,577.00	142,239.00	142,297.00	142,364.00	1,821,858.96
	5560 Total			**154,083.29**	**142,571.00**	**142,577.00**	**142,239.00**	**142,297.00**	**142,364.00**	**1,821,858.96**
										-
5570	**Other Expenses**	5570000	Other Expenses	339,464.02	292,616.00	292,631.00	292,087.00	292,179.00	292,298.00	3,549,304.11
		5570004	Deferred Fuel	2,974,804.91	-	-	-	-	-	4,038,021.65
		5570010	OH Auction Exp - Incremental		-	-	-	-	-	-
	5570 Total			**3,314,268.93**	**292,616.00**	**292,631.00**	**292,087.00**	**292,179.00**	**292,298.00**	**7,587,325.76**
										-
5600	**Oper Supervision & Engineering**	5600000	Oper Supervision & Engineering	1,114,905.39	298,001.00	297,724.00	303,278.00	302,876.00	302,425.00	7,240,688.44
	5600 Total			**1,114,905.39**	**298,001.00**	**297,724.00**	**303,278.00**	**302,876.00**	**302,425.00**	**7,240,688.44**
										-
5611	**Load Dispatching**	5611000	Load Dispatch - Reliability	-	14.00	14.00	14.00	14.00	14.00	121.31
	5611 Total			**-**	**14.00**	**14.00**	**14.00**	**14.00**	**14.00**	**121.31**
										-
5612	**Load Dispatching**	5612000	Load Dispatch-Mntr&Op TransSys	84,119.10	135,551.00	135,533.00	135,720.00	135,736.00	135,750.00	1,179,512.80
	5612 Total			**84,119.10**	**135,551.00**	**135,533.00**	**135,720.00**	**135,736.00**	**135,750.00**	**1,179,512.80**
										-
5613	**Load Dispatching**	5613000	Load Dispatch-Trans Srvc&Sched	35.82	121.00	121.00	122.00	122.00	122.00	1,056.96
	5613 Total			**35.82**	**121.00**	**121.00**	**122.00**	**122.00**	**122.00**	**1,056.96**
										-
5614	**Load Dispatching**	5614002	SPP Admin-SSC&DS	898,912.87	1,018,798.00	1,079,536.00	927,229.00	1,030,004.00	939,908.00	11,588,482.96
		5614005	ERCOT Admin-SSC&DS	0.04	-	-	-	-	-	4,938.58
		5614006	SPP Transmission Charges	458.09	2,934.00	18,510.00	26,285.00	25,042.00	24,080.00	100,118.18
		5614007	RTO Admin Default LSE.		-	-	-	-	-	-
	5614 Total			**899,371.00**	**1,021,732.00**	**1,098,046.00**	**953,514.00**	**1,055,046.00**	**963,988.00**	**11,693,539.72**
										-
5615	**Load Dispatching**	5615000	Reliability,Plng&Stds Develop	19,329.60	21,880.00	21,877.00	21,907.00	21,910.00	21,912.00	190,390.47
	5615 Total			**19,329.60**	**21,880.00**	**21,877.00**	**21,907.00**	**21,910.00**	**21,912.00**	**190,390.47**
										-
5616	**Load Dispatching**	5616000	Transmission Service Studies	-	11.00	11.00	11.00	11.00	11.00	94.33
	5616 Total			**-**	**11.00**	**11.00**	**11.00**	**11.00**	**11.00**	**94.33**
										-
5618	**Load Dispatching**	5618002	SPP Admin-RP&SDS	90,002.41	170,382.00	170,359.00	170,595.00	170,615.00	170,633.00	1,482,600.89
	5618 Total			**90,002.41**	**170,382.00**	**170,359.00**	**170,595.00**	**170,615.00**	**170,633.00**	**1,482,600.89**
										-
5620	**Station Expenses**	5620001	Station Expenses - Nonassoc	74,211.84	325.00	328.00	328.00	328.00	328.00	540,343.99
	5620 Total			**74,211.84**	**325.00**	**328.00**	**328.00**	**328.00**	**328.00**	**540,343.99**
										-
5630	**Overhead Line Expenses**	5630000	Overhead Line Expenses	73,226.01	2,010.00	2,021.00	2,021.00	2,021.00	2,021.00	421,894.87
	5630 Total			**73,226.01**	**2,010.00**	**2,021.00**	**2,021.00**	**2,021.00**	**2,021.00**	**421,894.87**

Southerwestern Electric Power Company
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FERC	FERC Title	Account	Description	7/31/2018	8/31/2018	9/30/2018	10/31/2018	11/30/2018	12/31/2018	Test Year Total
										-
5640	**Underground Line Expenses**	5640000	Underground Line Expenses							-
	5640 Total			-	-	-	-	-	-	-
										-
5650	**Trnsmssion of Elect by Others**	5650001	Transmssn Elec by Others-Assoc	3,684.04	3,684.00	3,684.00	3,684.00	3,684.00	3,684.00	44,208.28
		5650002	Transmssn Elec by Others-NAC	614,067.88	450,000.00	450,000.00	450,000.00	450,000.00	450,000.00	6,126,071.24
		5650007	Tran Elec by Oth-Aff-Trn Price	-						0.00
		5650009	SPP Affiliated Transmission Ex	5,732,335.56	2,179,582.00	2,171,972.00	2,129,483.00	1,579,673.00	1,790,212.00	22,946,838.53
		5650010	Tran Elec by Oth-Aff-SPP	-						-
		5650013	SPP Affil. Base Funding Exp	803,916.14	1,028,257.00	1,028,257.00	1,028,257.00	1,028,257.00	1,028,257.00	13,544,007.92
		5650014	SPP Non-Affil Base Funding Exp	4,018,539.31	3,735,642.00	3,735,642.00	3,735,642.00	4,047,758.00	4,047,758.00	49,137,568.04
		5650016	PJM NITS Expense - Affiliated	(2,598,681.00)	-	-	-	-	-	(16,455.00)
		5650020	PROVISION RTO Affl Expense	(2,157.76)	-	-	-	-	-	(70,683.98)
		5650046	SPP Transmission Expense	343,401.90	325,122.00	325,122.00	325,122.00	325,122.00	325,122.00	3,770,315.08
		5650047	SPP Pt to Pt Trans Affil Exp							-
		5650048	Affil. SPPAncillary Sch. 1 Exp	58,881.15	-	-	-	-	-	58,881.15
		5650052	SPP Transmission - Contra		175,601.00	175,601.00	175,601.00	175,601.00	175,601.00	878,005.00
	5650 Total			**8,973,987.22**	**7,897,888.00**	**7,890,278.00**	**7,847,789.00**	**7,610,095.00**	**7,820,634.00**	**96,418,756.26**
5660	**Misc Transmission Expenses**	5660000	Misc Transmission Expenses	(25,191.64)	107,264.00	106,223.00	106,050.00	106,063.00	106,074.00	1,591,732.90
		5660004	SPP FERC Assessment Fees		-	-	-	-	-	-
		5660008	R.King Trans Cnter Exp - Affil		7,349.00	7,349.00	7,349.00	7,349.00	7,349.00	36,745.00
	5660 Total			**(25,191.64)**	**114,613.00**	**113,572.00**	**113,399.00**	**113,412.00**	**113,423.00**	**1,628,477.90**
5670	**Rents**	5670001	Rents - Nonassociated	-	-	-	-	-	-	36,806.28
		5670002	Rents - Associated	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	5670 Total			**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**36,806.28**
										-
5680	**Maint Supv & Engineering**	5680000	Maint Supv & Engineering	7,456.54	-	-	-	-	-	41,077.34
	5680 Total			**7,456.54**	**-**	**-**	**-**	**-**	**-**	**41,077.34**
										-
5690	**Maintenance of Structures**	5690000	Maintenance of Structures	10,688.69	3,944.00	3,945.00	3,940.00	3,941.00	3,941.00	80,838.40
	5690 Total			**10,688.69**	**3,944.00**	**3,945.00**	**3,940.00**	**3,941.00**	**3,941.00**	**80,838.40**
										-
5691	**Maintenance of Structures**	5691000	Maint of Computer Hardware	849.33	193.00	193.00	192.00	192.00	192.00	3,946.21
	5691 Total			**849.33**	**193.00**	**193.00**	**192.00**	**192.00**	**192.00**	**3,946.21**
										-
5692	**Maintenance of Structures**	5692000	Maint of Computer Software	55,346.44	22,041.00	22,047.00	22,023.00	22,025.00	22,029.00	451,796.67
	5692 Total			**55,346.44**	**22,041.00**	**22,047.00**	**22,023.00**	**22,025.00**	**22,029.00**	**451,796.67**
										-
5693	**Maintenance of Structures**	5693000	Maint of Communication Equip	6,919.08	1,972.00	1,972.00	1,970.00	1,970.00	1,970.00	40,412.21
	5693 Total			**6,919.08**	**1,972.00**	**1,972.00**	**1,970.00**	**1,970.00**	**1,970.00**	**40,412.21**
										-
5700	**Maint of Station Equipment**	5700000	Maint of Station Equipment	185,785.16	479,743.00	486,216.00	486,114.00	486,051.00	485,890.00	3,594,257.68
	5700 Total			**185,785.16**	**479,743.00**	**486,216.00**	**486,114.00**	**486,051.00**	**485,890.00**	**3,594,257.68**
										-
5710	**Maintenance of Overhead Lines**	5710000	Maintenance of Overhead Lines	1,010,176.95	864,199.00	875,144.00	932,214.00	929,004.00	1,070,504.00	10,328,800.36
	5710 Total			**1,010,176.95**	**864,199.00**	**875,144.00**	**932,214.00**	**929,004.00**	**1,070,504.00**	**10,328,800.36**
										-
5720	**Maint of Underground Lines**	5720000	Maint of Underground Lines	201.61	-	-	-	-	-	749.63
	5720 Total			**201.61**	**-**	**-**	**-**	**-**	**-**	**749.63**
										-
5730	**Maint of Misc Trnsmssion Plt**	5730000	Maint of Misc Trnsmssion Plt	3,147.87	-	-	-	-	-	38,034.19
	5730 Total			**3,147.87**	**-**	**-**	**-**	**-**	**-**	**38,034.19**
										-
5757	**SPP Admin-MAM&SC**	5757002	SPP Admin-MAM&SC	193,243.82	4,224.00	362,104.00	129,957.00	(150,785.00)	236,080.00	1,514,935.66
	5757 Total			**193,243.82**	**4,224.00**	**362,104.00**	**129,957.00**	**(150,785.00)**	**236,080.00**	**1,514,935.66**
										-
5800	**Oper Supervision & Engineering**	5800000	Oper Supervision & Engineering	(492,896.80)	229,447.00	215,283.00	229,579.00	219,266.00	214,994.00	2,454,445.36
	5800 Total			**(492,896.80)**	**229,447.00**	**215,283.00**	**229,579.00**	**219,266.00**	**214,994.00**	**2,454,445.36**
										-
5810	**Load Dispatching**	5810000	Load Dispatching	4,425.01	52.00	52.00	52.00	52.00	52.00	31,526.71
	5810 Total			**4,425.01**	**52.00**	**52.00**	**52.00**	**52.00**	**52.00**	**31,526.71**
										-
5820	**Station Expenses**	5820000	Station Expenses	57,799.84	-	-	-	-	-	403,171.65

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Schedule E-17A

FERC	FERC Title	Account	Description	7/31/2018	8/31/2018	9/30/2018	10/31/2018	11/30/2018	12/31/2018	Test Year Total
		5820 Total		**57,799.84**	**-**	**-**	**-**	**-**	**-**	**403,171.65**
										-
5830	**Overhead Line Expenses**	5830000	Overhead Line Expenses	927,361.96	192,525.00	450,056.00	450,057.00	450,057.00	450,056.00	3,146,045.66
		5830 Total		**927,361.96**	**192,525.00**	**450,056.00**	**450,057.00**	**450,057.00**	**450,056.00**	**3,146,045.66**
										-
5840	**Underground Line Expenses**	5840000	Underground Line Expenses	137,570.18	230,279.00	235,003.00	234,951.00	234,988.00	235,001.00	2,141,965.94
		5840 Total		**137,570.18**	**230,279.00**	**235,003.00**	**234,951.00**	**234,988.00**	**235,001.00**	**2,141,965.94**
										-
5850	**Street Lighting & Signal Sys E**	5850000	Street Lighting & Signal Sys E	7,776.99	23,712.00	24,008.00	23,996.00	24,007.00	23,994.00	202,449.76
		5850 Total		**7,776.99**	**23,712.00**	**24,008.00**	**23,996.00**	**24,007.00**	**23,994.00**	**202,449.76**
										-
5860	**Meter Expenses**	5860000	Meter Expenses	331,216.50	266,500.00	266,562.00	274,807.00	268,623.00	266,476.00	3,518,815.47
		5860 Total		**331,216.50**	**266,500.00**	**266,562.00**	**274,807.00**	**268,623.00**	**266,476.00**	**3,518,815.47**
										-
5870	**Customer Installations Exp**	5870000	Customer Installations Exp	44,755.22	77,034.00	78,425.00	78,420.00	78,424.00	78,417.00	722,019.25
		5870 Total		**44,755.22**	**77,034.00**	**78,425.00**	**78,420.00**	**78,424.00**	**78,417.00**	**722,019.25**
										-
5880	**Miscellaneous Distribution Exp**	5880000	Miscellaneous Distribution Exp	1,151,787.73	1,652,096.00	1,659,139.00	1,664,786.00	1,661,502.00	1,704,296.00	19,094,222.97
		5880 Total		**1,151,787.73**	**1,652,096.00**	**1,659,139.00**	**1,664,786.00**	**1,661,502.00**	**1,704,296.00**	**19,094,222.97**
										-
5890	**Rents**	5890001	Rents - Nonassociated	72,753.29	72,500.00	72,500.00	72,500.00	72,500.00	72,500.00	876,368.79
		5890002	Rents - Associated	1,826.30	526.00	526.00	526.00	525.00	526.00	15,413.10
		5890 Total		**74,579.59**	**73,026.00**	**73,026.00**	**73,026.00**	**73,025.00**	**73,026.00**	**891,781.89**
										-
5900	**Maint Supv & Engineering**	5900000	Maint Supv & Engineering	19,059.00	37,268.00	37,743.00	37,743.00	37,743.00	37,743.00	369,094.99
		5900 Total		**19,059.00**	**37,268.00**	**37,743.00**	**37,743.00**	**37,743.00**	**37,743.00**	**369,094.99**
										-
5910	**Maintenance of Structures**	5910000	Maintenance of Structures	2,442.29	-	-	-	-	-	22,518.99
		5910 Total		**2,442.29**	**-**	**-**	**-**	**-**	**-**	**22,518.99**
										-
5920	**Maint of Station Equipment**	5920000	Maint of Station Equipment	127,442.54	5,143.00	5,222.00	5,235.00	5,235.00	5,235.00	664,100.37
		5920 Total		**127,442.54**	**5,143.00**	**5,222.00**	**5,235.00**	**5,235.00**	**5,235.00**	**664,100.37**
										-
5930	**Maintenance of Overhead Lines**	5930000	Maintenance of Overhead Lines	3,847,822.77	3,788,315.00	3,790,410.00	3,867,070.00	4,319,636.00	5,901,393.00	47,796,945.60
		5930007	Mnt O/H Line Reliability-Def		-	-	-	-	-	-
		5930 Total		**3,847,822.77**	**3,788,315.00**	**3,790,410.00**	**3,867,070.00**	**4,319,636.00**	**5,901,393.00**	**47,796,945.60**
										-
5940	**Maint of Underground Lines**	5940000	Maint of Underground Lines	28,427.66	105,604.00	107,362.00	107,356.00	107,361.00	107,356.00	1,021,214.16
		5940 Total		**28,427.66**	**105,604.00**	**107,362.00**	**107,356.00**	**107,361.00**	**107,356.00**	**1,021,214.16**
										-
5950	**Maint of Lne Trnf,Rglators&Dvi**	5950000	Maint of Lne Trnf,Rglators&Dvi	25,577.06	288.00	295.00	295.00	295.00	295.00	140,319.56
		5950 Total		**25,577.06**	**288.00**	**295.00**	**295.00**	**295.00**	**295.00**	**140,319.56**
										-
5960	**Maint of Strt Lghtng & Sgnal S**	5960000	Maint of Strt Lghtng & Sgnal S	28,584.17	23,284.00	23,802.00	23,802.00	23,802.00	23,802.00	392,933.14
		5960 Total		**28,584.17**	**23,284.00**	**23,802.00**	**23,802.00**	**23,802.00**	**23,802.00**	**392,933.14**
										-
5970	**Maintenance of Meters**	5970000	Maintenance of Meters	43,673.21	37,622.00	38,600.00	38,600.00	38,600.00	38,600.00	478,154.96
		5970 Total		**43,673.21**	**37,622.00**	**38,600.00**	**38,600.00**	**38,600.00**	**38,600.00**	**478,154.96**
										-
5980	**Maint of Misc Distribution Plt**	5980000	Maint of Misc Distribution Plt	28,558.92	15,087.00	15,453.00	15,452.00	15,453.00	15,452.00	245,998.03
		5980 Total		**28,558.92**	**15,087.00**	**15,453.00**	**15,452.00**	**15,453.00**	**15,452.00**	**245,998.03**
										-
9010	**Supervision - Customer Accts**	9010000	Supervision - Customer Accts	57,805.52	49,854.00	50,476.00	50,476.00	50,476.00	50,476.00	667,240.18
		9010 Total		**57,805.52**	**49,854.00**	**50,476.00**	**50,476.00**	**50,476.00**	**50,476.00**	**667,240.18**
										-
9020	**Meter Reading Expenses**	9020000	Meter Reading Expenses	30,177.85	23,691.00	23,917.00	24,060.00	23,953.00	23,910.00	290,164.49
		9020001	Customer Card Reading		-	-	-	-	-	-
		9020002	Meter Reading - Regular	161,838.21	146,327.00	147,720.00	148,609.00	147,944.00	147,681.00	1,792,197.24
		9020003	Meter Reading - Large Power	9,048.09	6,145.00	6,203.00	6,240.00	6,213.00	6,201.00	75,258.58
		9020004	Read-In & Read-Out Meters	237.86	290.00	293.00	295.00	294.00	293.00	3,557.27
		9020 Total		**201,302.01**	**176,453.00**	**178,133.00**	**179,204.00**	**178,404.00**	**178,085.00**	**2,161,177.58**
										-
9030	**Cust Records & Collection Exp**	9030000	Cust Records & Collection Exp	151,782.69	137,280.00	138,926.00	136,358.00	136,369.00	136,592.00	1,828,662.41

Southerwestern Electric Power Company
Trial Balance - Income Statement
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger sub fiscal or calendar years. Also, provide monthly trial balances fo

FERC	FERC Title	Account	Description	7/31/2018	8/31/2018	9/30/2018	10/31/2018	11/30/2018	12/31/2018	Test Year Total
		9030001	Customer Orders & Inquiries	812,081.64	644,366.00	652,093.00	640,039.00	640,091.00	641,138.00	8,583,408.05
		9030002	Manual Billing	5,253.35	5,237.00	5,300.00	5,202.00	5,202.00	5,211.00	69,760.38
		9030003	Postage - Customer Bills	136,505.96	114,115.00	115,484.00	113,349.00	113,358.00	113,544.00	1,520,098.03
		9030004	Cashiering	12,469.58	14,531.00	14,706.00	14,434.00	14,435.00	14,459.00	193,569.29
		9030005	Collection Agents Fees & Exp	17,355.67	14,610.00	14,785.00	14,512.00	14,513.00	14,537.00	194,613.38
		9030006	Credit & Oth Collection Activi	230,441.82	172,093.00	174,157.00	170,937.00	170,951.00	171,231.00	2,292,399.08
		9030007	Collectors	59,985.93	56,156.00	56,829.00	55,779.00	55,783.00	55,874.00	748,032.71
		9030009	Data Processing	38,427.06	32,593.00	32,984.00	32,374.00	32,377.00	32,430.00	434,161.38
	9030 Total			**1,464,303.70**	**1,190,981.00**	**1,205,264.00**	**1,182,984.00**	**1,183,079.00**	**1,185,016.00**	**15,864,704.71**
										-
9040	**Uncollectible Accounts**	9040007	Uncoll Accts - Misc Receivable	(0.08)	-	-	-	-	-	(525,204.90)
	9040 Total			**(0.08)**	**-**	**-**	**-**	**-**	**-**	**(525,204.90)**
										-
9050	**Misc Customer Accounts Exp**	9050000	Misc Customer Accounts Exp	6,637.56	18,143.00	18,379.00	18,114.00	18,290.00	18,358.00	146,806.02
	9050 Total			**6,637.56**	**18,143.00**	**18,379.00**	**18,114.00**	**18,290.00**	**18,358.00**	**146,806.02**
										-
9070	**Supervision - Customer Service**	9070000	Supervision - Customer Service	55,173.75	66,917.00	66,275.00	67,039.00	66,547.00	66,348.00	779,162.59
		9070001	Supervision - DSM	376,437.46	563,807.00	558,392.00	564,822.00	560,691.00	559,008.00	6,564,725.81
		9070014	DSM Costs Deferred - TEXAS	303,994.04	70,508.00	19,393.00	(30,567.00)	(45,609.00)	6,521.00	103,226.05
	9070 Total			**735,605.25**	**701,232.00**	**644,060.00**	**601,294.00**	**581,629.00**	**631,877.00**	**7,447,114.45**
										-
9080	**Customer Assistance Expenses**	9080000	Customer Assistance Expenses	181,033.13	201,449.00	201,178.00	201,178.00	201,178.00	201,178.00	2,141,388.35
		9080001	DSM-Customer Advisory Grp		-	-	-	-	-	46.04
		9080004	Cust Assistnce Exp - DSM - Ind		-	-	-	-	-	(489.79)
		9080009	Cust Assistance Expense - DSM	873,550.91	869,051.00	869,130.00	868,986.00	869,083.00	869,120.00	9,888,985.09
		9080014	DSM Costs Deferred	666,103.90	247,945.00	80,072.00	(96,473.00)	(122,132.00)	(30,452.00)	1,831,696.17
	9080 Total			**1,720,687.94**	**1,318,445.00**	**1,150,380.00**	**973,691.00**	**948,129.00**	**1,039,846.00**	**13,861,625.86**
										-
9090	**Information & Instruct Advrtis**	9090000	Information & Instruct Advrtis	-	2,852.00	2,852.00	2,852.00	2,852.00	2,852.00	14,452.99
	9090 Total			**-**	**2,852.00**	**2,852.00**	**2,852.00**	**2,852.00**	**2,852.00**	**14,452.99**
										-
9100	**Misc Cust Svc&Informational Ex**	9100000	Misc Cust Svc&Informational Ex	1,086.49	-	-	-	-	-	6,899.22
		9100001	Misc Cust Svc & Info Exp - RCS	-	-	-	-	-	-	22.38
	9100 Total			**1,086.49**	**-**	**-**	**-**	**-**	**-**	**6,921.60**
										-
9110	**Supervision - Sales Expenses**	9110001	Supervision - Residential	(36.84)	-	-	-	-	-	-
		9110002	Supervision - Comm & Ind	-	-	-	-	-	-	321.35
	9110 Total			**(36.84)**	**-**	**-**	**-**	**-**	**-**	**321.35**
										-
9120	**Demonstrating & Selling Exp**	9120000	Demonstrating & Selling Exp	6,921.30	13,080.00	11,902.00	13,105.00	11,544.00	13,105.00	166,230.74
		9120001	Demo & Selling Exp - Res	-	-	-	-	-	-	2.08
	9120 Total			**6,921.30**	**13,080.00**	**11,902.00**	**13,105.00**	**11,544.00**	**13,105.00**	**166,232.82**
										-
9130	**Advertising Exp**	9130001	Advertising Exp - Residential	-	-	-	-	-	-	-
	9130 Total			**-**	**-**	**-**	**-**	**-**	**-**	**-**
										-
9200	**Administrative & Gen Salaries**	9200000	Administrative & Gen Salaries	2,482,355.32	3,013,753.00	3,014,481.00	3,170,929.00	3,172,213.00	3,173,499.00	32,439,794.20
		9200005	GridSmart Reimbursement Contra	-	-	-	-	-	-	-
	9200 Total			**2,482,355.32**	**3,013,753.00**	**3,014,481.00**	**3,170,929.00**	**3,172,213.00**	**3,173,499.00**	**32,439,794.20**
										-
9210	**Office Supplies and Expenses**	9210001	Off Supl & Exp - Nonassociated	232,812.14	231,472.00	230,147.00	229,456.00	237,483.00	233,534.00	2,821,900.60
		9210002	Off Supl & Exp - Associated	8,663.14	10,058.00	10,000.00	9,970.00	10,319.00	10,147.00	122,615.33
		9210003	Office Supplies & Exp - Trnsf	-	92.00	92.00	91.00	95.00	93.00	1,124.58
		9210004	Office Utilites		-	-	-	-	-	-
		9210005	Cellular Phones and Pagers		-	-	-	-	-	-
		9210007	Dresden Off Supl & Exp Nonasoc	-	-	-	-	-	-	2.99
	9210 Total			**241,475.28**	**241,622.00**	**240,239.00**	**239,517.00**	**247,897.00**	**243,774.00**	**2,945,643.50**
										-
9220	**Administrative Exp Trnsf - Cr**	9220000	Administrative Exp Trnsf - Cr	(127,278.00)	(133,857.00)	(133,858.00)	(133,858.00)	(133,857.00)	(133,858.00)	(2,027,794.85)
		9220001	Admin Exp Trnsf to Cnstrction	(198,506.00)	(107,363.00)	(107,363.00)	(107,363.00)	(107,363.00)	(107,363.00)	(1,626,424.00)
		9220004	Admin Exp Trnsf to ABD	(1,223.90)	(1,154.00)	(1,154.00)	(1,154.00)	(1,154.00)	(1,154.00)	(17,479.70)
	9220 Total			**(327,007.90)**	**(242,374.00)**	**(242,375.00)**	**(242,375.00)**	**(242,374.00)**	**(242,375.00)**	**(3,671,698.55)**
										-

Southerwestern Electric Power Company
Trial Balance - Income Statement
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger sub fiscal or calendar years. Also, provide monthly trial balances fo

FERC	FERC Title	Account	Description	7/31/2018	8/31/2018	9/30/2018	10/31/2018	11/30/2018	12/31/2018	Test Year Total
9230	**Outside Services Employed**	9230001	Outside Svcs Empl - Nonassoc	606,424.42	3,066,492.00	2,483,774.00	2,493,007.00	2,492,396.00	2,492,397.00	16,433,000.44
		9230003	AEPSC Billed to Client Co	(293,621.89)	319,217.00	315,473.00	412,501.00	381,731.00	349,082.00	1,218,884.02
	9230 Total			**312,802.53**	**3,385,709.00**	**2,799,247.00**	**2,905,508.00**	**2,874,127.00**	**2,841,479.00**	**17,651,884.46**
										-
9240	**Property Insurance**	9240000	Property Insurance	185,865.75	200,558.00	200,558.00	200,557.00	200,557.00	200,558.00	2,605,012.40
	9240 Total			**185,865.75**	**200,558.00**	**200,558.00**	**200,557.00**	**200,557.00**	**200,558.00**	**2,605,012.40**
										-
9250	**Injuries and Damages**	9250000	Injuries and Damages	442,273.43	258,201.00	258,191.00	270,557.00	258,357.00	260,707.00	3,314,440.71
		9250001	Safety Dinners and Awards		13.00	13.00	14.00	13.00	13.00	169.48
		9250002	Emp Accdent Prvntion-Adm Exp	28,458.28	21,508.00	21,507.00	22,537.00	21,521.00	21,717.00	276,091.05
		9250004	Injuries to Employees		-	-	-	-	-	-
		9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	(34,451.02)	79,590.00	79,587.00	83,399.00	79,639.00	80,363.00	1,021,675.18
		9250007	Prsnal Injries&Prop Dmage-Pub	13,197.86	12,630.00	12,630.00	13,235.00	12,638.00	12,753.00	162,131.42
		9250010	Frg Ben Loading - Workers Comp	(21,449.03)	(13,426.00)	(13,426.00)	(14,069.00)	(13,434.00)	(13,557.00)	(172,348.58)
	9250 Total			**428,029.52**	**358,516.00**	**358,502.00**	**375,673.00**	**358,734.00**	**361,996.00**	**4,602,159.26**
										-
9260	**Employee Pensions & Benefits**	9260000	Employee Pensions & Benefits	(110,574.16)	(137,990.00)	(140,622.00)	(140,692.00)	(140,545.00)	(140,197.00)	(1,399,047.55)
		9260001	Edit & Print Empl Pub-Salaries	6,583.66	6,998.00	7,132.00	7,135.00	7,128.00	7,110.00	70,952.45
		9260002	Pension & Group Ins Admin	5,531.96	9,579.00	9,761.00	9,766.00	9,756.00	9,732.00	97,115.92
		9260003	Pension Plan	770,217.33	767,633.00	767,632.00	767,633.00	767,632.00	767,632.00	9,229,683.32
		9260004	Group Life Insurance Premiums	42,599.24	60,556.00	61,711.00	61,742.00	61,677.00	61,524.00	613,961.27
		9260005	Group Medical Ins Premiums	1,318,108.37	1,791,766.00	1,825,938.00	1,826,859.00	1,824,938.00	1,820,420.00	18,166,292.16
		9260006	Physical Examinations		-	-	-	-	-	-
		9260007	Group L-T Disability Ins Prem	59,094.95	69,457.00	70,782.00	70,817.00	70,743.00	70,568.00	704,208.82
		9260009	Group Dental Insurance Prem	61,438.59	85,105.00	86,728.00	86,772.00	86,680.00	86,466.00	862,858.23
		9260010	Training Administration Exp	2,891.72	882.00	899.00	900.00	899.00	896.00	8,945.30
		9260012	Employee Activities	4,411.78	6,483.00	6,607.00	6,610.00	6,603.00	6,587.00	65,730.73
		9260014	Educational Assistance Pmts	3,844.15	14,203.00	14,474.00	14,481.00	14,466.00	14,430.00	143,999.98
		9260021	Postretirement Benefits - OPEB	74,962.41	103,588.00	105,564.00	105,617.00	105,506.00	105,245.00	1,050,256.89
		9260026	Savings Plan Administration		(22.00)	(22.00)	(22.00)	(22.00)	(22.00)	(219.82)
		9260027	Savings Plan Contributions	464,434.03	690,426.00	703,594.00	703,949.00	703,209.00	701,468.00	7,000,071.14
		9260036	Deferred Compensation		839.00	855.00	855.00	855.00	852.00	8,506.30
		9260037	Supplemental Pension	2,594.08	2,585.00	2,585.00	2,585.00	2,585.00	2,585.00	31,083.57
		9260040	SFAS 112 Postemployment Benef		139,755.00	142,420.00	142,492.00	142,342.00	141,990.00	1,416,941.00
		9260042	SERP Pension - Non-Service	10,603.76	15,906.00	15,906.00	15,906.00	15,906.00	15,906.00	153,756.29
		9260043	OPEB - Non-Service	(680,020.42)	(1,020,031.00)	(1,020,031.00)	(1,020,031.00)	(1,020,031.00)	(1,020,031.00)	(9,860,297.93)
		9260050	Frg Ben Loading - Pension	(210,213.36)	(339,094.00)	(345,562.00)	(345,736.00)	(345,372.00)	(344,517.00)	(3,437,997.93)
		9260051	Frg Ben Loading - Grp Ins	(409,292.43)	(630,772.00)	(642,802.00)	(643,126.00)	(642,450.00)	(640,860.00)	(6,395,249.45)
		9260052	Frg Ben Loading - Savings	(133,226.89)	(210,913.00)	(214,935.00)	(215,044.00)	(214,818.00)	(214,286.00)	(2,138,396.81)
		9260053	Frg Ben Loading - OPEB	(61,337.58)	(58,930.00)	(60,053.00)	(60,084.00)	(60,021.00)	(59,872.00)	(597,473.60)
		9260055	IntercoFringeOffset- Don't Use	(270,841.36)	(360,190.00)	(367,060.00)	(367,245.00)	(366,859.00)	(365,951.00)	(3,651,886.02)
		9260058	Frg Ben Loading - Accrual	(142,575.31)	(74,167.00)	(75,582.00)	(75,620.00)	(75,540.00)	(75,353.00)	(751,962.48)
		9260060	Amort-Post Retirement Benefit	44,442.50	61,414.00	62,585.00	62,617.00	62,551.00	62,396.00	622,660.50
		9260062	Pension Plan - Non-Service	(93,904.17)	(140,856.00)	(140,856.00)	(140,856.00)	(140,856.00)	(140,856.00)	(1,361,609.18)
	9260 Total			**759,772.85**	**854,210.00**	**877,648.00**	**878,280.00**	**876,962.00**	**873,862.00**	**10,652,883.10**
										-
9270	**Franchise Requirements**	9270000	Franchise Requirements							-
	9270 Total			**-**	**-**	**-**	**-**	**-**	**-**	**-**
										-
9280	**Regulatory Commission Exp**	9280000	Regulatory Commission Exp	124.83	3.00	3.00	3.00	3.00	3.00	3,402.50
		9280001	Regulatory Commission Exp-Adm	-	28.00	28.00	28.00	28.00	28.00	36,845.00
		9280002	Regulatory Commission Exp-Case	441,101.29	2,083.00	2,083.00	2,083.00	2,083.00	2,083.00	2,716,229.24
		9280003	Rate Case Amort	-	25,192.00	25,192.00	25,192.00	25,192.00	25,192.00	125,960.00
		9280005	Reg Com Exp-FERC Trans Cases	9,956.39	58.00	58.00	58.00	58.00	58.00	75,697.10
	9280 Total			**451,182.51**	**27,364.00**	**27,364.00**	**27,364.00**	**27,364.00**	**27,364.00**	**2,958,133.84**
										-
9301	**General Advertising Expenses**	9301000	General Advertising Expenses	1,189.72	7,313.00	7,312.00	7,311.00	7,312.00	7,311.00	109,008.98
		9301001	Newspaper Advertising Space	1,395.00	1,267.00	1,267.00	1,267.00	1,267.00	1,267.00	18,889.06
		9301002	Radio Station Advertising Time	800.00	983.00	983.00	983.00	983.00	983.00	14,652.46
		9301003	TV Station Advertising Time		-	-	-	-	-	-
		9301010	Publicity		89.00	89.00	89.00	89.00	89.00	1,323.61
		9301012	Public Opinion Surveys	9,514.98	3,496.00	3,496.00	3,496.00	3,496.00	3,495.00	52,118.33
		9301015	Other Corporate Comm Exp	3,566.37	4,213.00	4,213.00	4,212.00	4,213.00	4,212.00	62,806.94

Southerwestern Electric Power Company
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FERC	FERC Title	Account	Description	7/31/2018	8/31/2018	9/30/2018	10/31/2018	11/30/2018	12/31/2018	Test Year Total
	9301 Total			**16,466.07**	**17,361.00**	**17,360.00**	**17,358.00**	**17,360.00**	**17,357.00**	**258,799.38**
										-
9302	**Misc General Expenses**	9302000	Misc General Expenses	9,724.13	28,084.00	28,079.00	28,079.00	28,079.00	28,078.00	727,379.66
		9302003	Corporate & Fiscal Expenses	1,988.08	2,378.00	2,378.00	2,378.00	2,378.00	2,378.00	61,602.27
		9302004	Research, Develop&Demonstr Exp	360.16	121.00	121.00	121.00	121.00	121.00	3,125.70
		9302006	Assoc Bus Dev - Materials Sold	561.02	4,218.00	4,244.00	4,371.00	4,305.00	4,282.00	44,045.88
		9302007	Assoc Business Development Exp	29,600.15	41,833.00	42,099.00	43,351.00	42,696.00	42,469.00	436,862.51
	9302 Total			**42,233.54**	**76,634.00**	**76,921.00**	**78,300.00**	**77,579.00**	**77,328.00**	**1,273,016.02**
										-
9310	**Rents**	9310000	Rents		-	-	-	-	-	24,136.51
		9310001	Rents - Real Property	50,600.78	25,166.00	24,521.00	24,161.00	23,554.00	23,294.00	277,504.89
		9310002	Rents - Personal Property	43,816.89	53,947.00	52,563.00	51,791.00	50,490.00	49,933.00	594,863.18
	9310 Total			**94,417.67**	**79,113.00**	**77,084.00**	**75,952.00**	**74,044.00**	**73,227.00**	**896,504.58**
										-
9350	**Maintenance of General Plant**	9350000	Maintenance of General Plant		34.00	34.00	34.00	34.00	34.00	487.84
		9350001	Maint of Structures - Owned	40,491.50	76,161.00	76,673.00	76,663.00	76,667.00	76,662.00	1,099,901.97
		9350002	Maint of Structures - Leased	348.56	7.00	7.00	7.00	7.00	7.00	100.12
		9350012	Maint of Data Equipment	1,960.74	1,464.00	1,473.00	1,473.00	1,473.00	1,473.00	21,135.43
		9350013	Maint of Cmmncation Eq-Unall	254,293.06	164,591.00	165,697.00	165,675.00	165,684.00	165,674.00	2,376,993.27
		9350014	Maint Supv & Eng-Cmmun Eq		-	-	-	-	-	-
		9350015	Maint of Office Furniture & Eq	229,015.86	196,947.00	198,271.00	198,246.00	198,256.00	198,245.00	2,844,287.04
		9350019	Maint of Gen Plant-SCADA Equ	252.93	181.00	182.00	182.00	182.00	182.00	2,609.31
		9350024	Maint of DA-AMI Comm Equip	(263.77)	3.00	3.00	3.00	3.00	3.00	46.87
	9350 Total			**526,098.88**	**439,388.00**	**442,340.00**	**442,283.00**	**442,306.00**	**442,280.00**	**6,345,561.85**
										-
4010	**Operation Expense**	4010001	Operation Exp - Nonassociated	3,357.18	-	-	-	-	-	8,935.81
	4010 Total			**3,357.18**	**-**	**-**	**-**	**-**	**-**	**8,935.81**
										-
4030	**Depreciation Expense**	4030001	Depreciation Exp	17,593,064.85	19,255,144.00	19,269,211.00	19,318,072.00	19,408,295.00	19,480,564.00	220,382,967.22
		4030028	Depreciation Expense Deferred	331,412.75	-	-	-	-	-	1,365,327.74
	4030 Total			**17,924,477.60**	**19,255,144.00**	**19,269,211.00**	**19,318,072.00**	**19,408,295.00**	**19,480,564.00**	**221,748,294.96**
										-
4031	**Depr - Asset Retirement Oblig**	4031001	Depr - Asset Retirement Oblig	120,549.11	123,058.00	123,058.00	123,058.00	123,058.00	123,059.00	1,474,281.18
	4031 Total			**120,549.11**	**123,058.00**	**123,058.00**	**123,058.00**	**123,058.00**	**123,059.00**	**1,474,281.18**
										-
4037	**Depreciation Expense**	4037000	Amort-TX Cap Impairment	(121,889.79)	(122,402.00)	(122,544.00)	(122,687.00)	(122,830.00)	(122,972.00)	(1,466,663.53)
		4037001	Amort TX SERP	(991.45)	(1,004.00)	(1,006.00)	(1,007.00)	(1,008.00)	(1,009.00)	(12,035.90)
		4037002	Amort TX RWIP Cap Incen	(466.09)	(465.00)	(465.00)	(466.00)	(466.00)	(467.00)	(5,567.63)
		4037003	Amort TX CWIP Cap Incent	(12,191.34)	(12,008.00)	(12,022.00)	(12,036.00)	(12,050.00)	(12,064.00)	(143,883.55)
		4037004	Amort TX Cap Veg Mgmt Costs	(11,337.80)	(11,217.00)	(11,230.00)	(11,243.00)	(11,256.00)	(11,270.00)	(134,408.56)
	4037 Total			**(146,876.46)**	**(147,096.00)**	**(147,267.00)**	**(147,439.00)**	**(147,610.00)**	**(147,782.00)**	**(1,762,559.16)**
										-
4040	**Amortization of Plant**	4040001	Amort. of Plant	1,429,303.10	1,505,510.00	1,464,323.00	1,559,843.00	1,660,048.00	1,746,718.00	17,638,899.11
	4040 Total			**1,429,303.10**	**1,505,510.00**	**1,464,323.00**	**1,559,843.00**	**1,660,048.00**	**1,746,718.00**	**17,638,899.11**
										-
4073	**Regulatory Debits**	4073000	Regulatory Debits	272,033.55	231,744.00	231,815.00	231,887.00	231,958.00	232,031.00	1,975,535.65
		4073016	Welsh Unit 2 Reg Asset Amort	40,873.62	80,674.00	80,699.00	80,724.00	80,749.00	80,774.00	687,717.46
		4073017	Welsh U2 ARO Reg Asset Amort	593.34	1,179.00	1,180.00	1,180.00	1,181.00	1,181.00	10,054.38
	4073 Total			**313,500.51**	**313,597.00**	**313,694.00**	**313,791.00**	**313,888.00**	**313,986.00**	**2,673,307.49**
										-
4074	**Regulatory Credits**	4074000	Regulatory Credits	(6,000.00)	(6,000.00)	(6,000.00)	(6,000.00)	(6,000.00)	(6,000.00)	(72,000.00)
	4074 Total			**(6,000.00)**	**(6,000.00)**	**(6,000.00)**	**(6,000.00)**	**(6,000.00)**	**(6,000.00)**	**(72,000.00)**
										-
4081	**Taxes Other Than Inc Tax, UOI**	4081002	FICA	872,807.06	906,889.00	957,934.00	958,359.00	956,161.00	949,232.00	10,876,194.44
		4081003	Federal Unemployment Tax	422.14	5,152.00	5,152.00	5,152.00	5,152.00	5,152.00	58,748.35
		40810051	Real Personal Property Taxes		-	-	-	-	-	-
		40810051	Real Personal Property Taxes		-	-	-	-	-	-
		40810051	Real Personal Property Taxes	10,459.70	(77,824.00)	(77,824.00)	(77,824.00)	(77,824.00)	(77,824.00)	(911,696.28)
		40810051	Real Personal Property Taxes	5,257,017.00	5,480,344.00	5,480,344.00	5,480,344.00	5,480,344.00	5,480,344.00	64,201,415.33
		40810061	State Gross Receipts Tax		-	-	-	-	-	-
		40810061	State Gross Receipts Tax		-	-	-	-	-	-
		40810061	State Gross Receipts Tax	-	-	-	-	-	-	2.00
		40810061	State Gross Receipts Tax	562,552.63	627,000.00	627,000.00	458,000.00	458,000.00	458,000.00	6,037,591.19

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FERC	FERC Title	Account	Description	7/31/2018	8/31/2018	9/30/2018	10/31/2018	11/30/2018	12/31/2018	Test Year Total
		4081007	State Unemployment Tax	520.76	10,178.00	10,178.00	10,178.00	10,178.00	10,178.00	79,692.21
		40810081	State Franchise Taxes		-	-	-	-	-	-
		40810081	State Franchise Taxes		-	-	-	-	-	-
		40810081	State Franchise Taxes	1,167,000.00	-	-	1,400,000.00	-	-	5,165,950.96
		40810141	Federal Excise Taxes		-	-	-	-	-	-
		40810141	Federal Excise Taxes		-	-	-	-	-	-
		40810141	Federal Excise Taxes	-	-	-	-	-	-	517.92
		40810141	Federal Excise Taxes	406.74	-	-	-	-	-	406.74
		40810171	St Lic-Rgstrtion Tax-Fees							-
		40810171	St Lic-Rgstrtion Tax-Fees	-	-	-	-	-	-	14,575.00
		40810171	St Lic-Rgstrtion Tax-Fees	-	-	-	-	-	-	17,070.00
		40810181	St Publ Serv Comm Tax-Fees		-	-	-	-	-	-
		40810181	St Publ Serv Comm Tax-Fees		-	-	-	-	-	-
		40810181	St Publ Serv Comm Tax-Fees	-	-	-	-	-	-	731,124.61
		40810181	St Publ Serv Comm Tax-Fees	171,721.00	178,000.00	178,000.00	158,000.00	158,000.00	158,000.00	1,252,713.72
		40810190	State Sales and Use Taxes	-	-	-	-	-	-	(311,500.00)
		40810191	State Sales and Use Taxes		-	-	-	-	-	-
		40810191	State Sales and Use Taxes		-	-	-	-	-	-
		40810191	State Sales and Use Taxes	-	-	-	-	-	-	185,276.60
		40810191	State Sales and Use Taxes	-	-	-	-	-	-	245.80
		40810191	State Sales and Use Taxes	0.01	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	4,875.82
		40810221	Municipal License Fees							-
		40810221	Municipal License Fees							-
		40810221	Municipal License Fees	-	-	-	-	-	-	80,475.00
		40810231	Local Privilege-Franchise Tax							-
		40810231	Local Privilege-Franchise Tax							-
		40810231	Local Privilege-Franchise Tax	1,958,788.29	1,829,000.00	1,733,000.00	1,525,000.00	1,226,000.00	1,295,000.00	18,005,587.28
		40810271	Misc State and Local Taxes		-	-	-	-	-	-
		40810291	Real-Pers Prop Tax-Cap Leases		-	-	-	-	-	-
		40810291	Real-Pers Prop Tax-Cap Leases		-	-	-	-	-	-
		40810291	Real-Pers Prop Tax-Cap Leases		-	-	-	-	-	9,468.86
		40810291	Real-Pers Prop Tax-Cap Leases	14,417.00	8,583.00	8,583.00	8,583.00	8,583.00	8,583.00	143,834.00
		4081033	Fringe Benefit Loading - FICA	(236,389.86)	(285,855.00)	(297,425.00)	(297,466.00)	(297,088.00)	(295,721.00)	(3,379,244.19)
		4081034	Fringe Benefit Loading - FUT	(1,523.06)	(1,605.00)	(1,606.00)	(1,605.00)	(1,606.00)	(1,605.00)	(19,508.46)
		4081035	Fringe Benefit Loading - SUT	(1,508.34)	(2,945.00)	(2,946.00)	(2,945.00)	(2,945.00)	(2,944.00)	(30,556.71)
	4081 Total			**9,776,691.07**	**8,677,917.00**	**8,621,390.00**	**9,624,776.00**	**7,923,955.00**	**7,987,395.00**	**102,213,260.19**
										-
4082	**Real Personal Property Taxes**	40820051	Real Personal Property Taxes	-	-	-	-	-	-	-
		40820051	Real Personal Property Taxes	-	-	-	-	-	-	-
	4082 Total			**-**	**-**	**-**	**-**	**-**	**-**	**-**
										-
4091	**Income Taxes, Utility Oper Inc**	4091001	Income Taxes, UOI - Federal	5,670,062.56	8,396,138.00	3,016,145.00	(2,981,976.00)	(3,593,915.00)	(764,039.00)	22,913,183.18
		40910020	Income Taxes, UOI - State		-	-	-	-	-	-
		40910021	Income Taxes UOI - State		-	-	-	-	-	-
		40910021	Income Taxes UOI - State		-	-	-	-	-	-
		40910021	Income Taxes UOI - State		-	-	-	-	-	-
		40910021	Income Taxes UOI - State	1,653,199.65	1,920,258.00	657,988.00	(764,434.00)	(904,251.00)	(231,498.00)	4,518,352.21
	4091 Total			**7,323,262.21**	**10,316,396.00**	**3,674,133.00**	**(3,746,410.00)**	**(4,498,166.00)**	**(995,537.00)**	**27,431,535.39**
										-
4092	**Income Tax, Oth Inc & Ded**	4092001	Inc Tax, Oth Inc&Ded-Federal	(760,069.23)	(643,446.00)	101,267.00	126,148.00	27,334.00	20,802.00	(6,716,051.84)
		40920021	Inc Tax Oth Inc Ded - State	-	-	-	-	-	-	-
		40920021	Inc Tax Oth Inc Ded - State	-	-	-	-	-	-	-
		40920021	Inc Tax Oth Inc Ded - State	-	-	-	-	-	-	-
		40920021	Inc Tax Oth Inc Ded - State	(146,800.66)	(143,299.00)	22,553.00	28,094.00	6,088.00	4,633.00	(1,344,499.03)
	4092 Total			**(906,869.89)**	**(786,745.00)**	**123,820.00**	**154,242.00**	**33,422.00**	**25,435.00**	**(8,060,550.87)**
										-
4101	**Prov Def Inc Tax, Util Oper In**	4101001	Prov Def I/T Util Op Inc-Fed	2,825,272.75	(1,801,140.00)	2,182,566.00	2,365,625.00	2,285,977.00	2,150,876.00	775,266,830.54
		4101002	Prov Def I/T Util Op Inc-State	-	-	-	-	-	-	1,825,929.73
	4101 Total			**2,825,272.75**	**(1,801,140.00)**	**2,182,566.00**	**2,365,625.00**	**2,285,977.00**	**2,150,876.00**	**777,092,760.27**
										-
4102	**Prov Def I/T Oth Inc & Ded**	4102001	Prov Def I/T Oth I&D - Federal	135,030.00	-	-	-	-	-	2,024,666.54
	4102 Total			**135,030.00**	**-**	**-**	**-**	**-**	**-**	**2,024,666.54**
										-

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4111	**Prov Def I/T-Cr Util Oper Inc**	4111001	Prv Def I/T-Cr Util Op Inc-Fed	(4,097,025.62)	(1,754,765.00)	(2,329,746.00)	(2,241,704.00)	(2,241,704.00)	(2,241,704.00)	(782,342,934.06)
		4111002	Prv Def I/T-Cr UtilOpInc-State	-	-	-	-	-	-	(1,395,115.83)
		4111005	Accretion Expense	219,596.39	200,194.00	201,199.00	202,209.00	203,225.00	204,246.00	2,558,193.25
	4111 Total			**(3,877,429.23)**	**(1,554,571.00)**	**(2,128,547.00)**	**(2,039,495.00)**	**(2,038,479.00)**	**(2,037,458.00)**	**(781,179,856.64)**
										-
4112	**Prv Def I/T-Cr Oth I&D**	4112001	Prv Def I/T-Cr Oth I&D-Fed	-	-	-	-	-	-	(1,079,456.55)
	4112 Total			**-**	**-**	**-**	**-**	**-**	**-**	**(1,079,456.55)**
										-
4114	**ITC Adj, Utility Operations**	4114001	ITC Adj, Utility Oper - Fed	(118,518.00)	(82,954.00)	(82,954.00)	(82,954.00)	(82,954.00)	(82,954.00)	(1,244,396.00)
	4114 Total			**(118,518.00)**	**(82,954.00)**	**(82,954.00)**	**(82,954.00)**	**(82,954.00)**	**(82,954.00)**	**(1,244,396.00)**
										-
4116	**Gain From Disposition of Plant**	4116000	Gain From Disposition of Plant	-	-	-	-	-	-	619,211.74
	4116 Total			**-**	**-**	**-**	**-**	**-**	**-**	**619,211.74**
										-
4118	**Gain Disposition of Allowances**	4118002	Comp. Allow Gains Title IV SO2	-	-	-	-	-	-	(84.45)
		4118006	CSAPR SO2 Gains	-	-	-	-	-	-	-
		4118008	Comp Allow Gain CSAPR Seas NOx	-	-	-	-	-	-	-
		4118009	Comp Allow Gains CSAPR An NOx	-	-	-	-	-	-	-
	4118 Total			**-**	**-**	**-**	**-**	**-**	**-**	**(84.45)**
										-
4180	**Non-Operatng Rental Income**	4180001	Non-Operatng Rental Income	-	-	-	-	-	-	(234.56)
		4180003	Non-Opratng Rntal Inc-Maint	-	-	-	-	-	-	-
	4180 Total			**-**	**-**	**-**	**-**	**-**	**-**	**(234.56)**
										-
4181	**Equity Erngs of Subsidiary Co**	4181001	Equity Erngs of Sub-Consolidat	(3,213.81)	-	-	-	-	-	(18,290.05)
		4181002	Equity Erngs of Sub-Nonconsol	(269,664.32)	(326,659.00)	(247,825.00)	(231,627.00)	(152,717.00)	(116,956.00)	(2,517,466.34)
	4181 Total			**(272,878.13)**	**(326,659.00)**	**(247,825.00)**	**(231,627.00)**	**(152,717.00)**	**(116,956.00)**	**(2,535,756.39)**
										-
4190	**Interest & Dividend Income**	4190002	Int & Dividend Inc - Nonassoc	(213,368.91)	(195,370.00)	(192,000.00)	(191,000.00)	(190,000.00)	(189,000.00)	(3,007,903.04)
		4190005	Interest Income - Assoc CBP	-	-	(539,662.00)	(628,741.00)	(84,997.00)	(28,257.00)	(1,822,443.32)
	4190 Total			**(213,368.91)**	**(195,370.00)**	**(731,662.00)**	**(819,741.00)**	**(274,997.00)**	**(217,257.00)**	**(4,830,346.36)**
										-
4191	**Allw Oth Fnds Usd Drng Cnstr**	4191000	Allw Oth Fnds Usd Drng Cnstr	(175,331.43)	(621,139.00)	(695,653.00)	(794,404.00)	(929,313.00)	(889,663.00)	(7,298,637.66)
	4191 Total			**(175,331.43)**	**(621,139.00)**	**(695,653.00)**	**(794,404.00)**	**(929,313.00)**	**(889,663.00)**	**(7,298,637.66)**
										-
4210	**Misc Non-Operating Income**	4210002	Misc Non-Op Inc-NonAsc-Rents	(203.16)	(334.00)	(308.00)	(308.00)	(308.00)	(308.00)	(3,309.53)
		4210003	Misc Non-Op Inc-NonAscRoylty		-	-	-	-	-	-
		4210005	Misc Non-Op Inc-NonAsc-Timber		-	-	-	-	-	-
		4210007	Misc Non-Op Inc - NonAsc - Oth	(38,465.19)	(64,666.00)	(59,692.00)	(59,692.00)	(59,692.00)	(59,692.00)	(641,491.62)
		4210009	Misc Non-Op Exp - NonAssoc	1,242.93	-	-	-	-	-	4,755.63
	4210 Total			**(37,425.42)**	**(65,000.00)**	**(60,000.00)**	**(60,000.00)**	**(60,000.00)**	**(60,000.00)**	**(640,045.52)**
										-
4211	**Gain on Dspsition of Property**	4211000	Gain on Dspsition of Property		(499,062.00)	(675,234.00)	(675,234.00)	(675,234.00)	(675,235.00)	(3,199,999.00)
	4211 Total			**-**	**(499,062.00)**	**(675,234.00)**	**(675,234.00)**	**(675,234.00)**	**(675,235.00)**	**(3,199,999.00)**
										-
4212	**Loss on Dspsition of Property**	4212000	Loss on Dspsition of Property							-
	4212 Total			**-**	**-**	**-**	**-**	**-**	**-**	**-**
										-
4261	**Donations**	4261000	Donations	80,595.78	63,789.00	63,789.00	63,789.00	63,789.00	63,789.00	626,457.69
	4261 Total			**80,595.78**	**63,789.00**	**63,789.00**	**63,789.00**	**63,789.00**	**63,789.00**	**626,457.69**
										-
4263	**Penalties**	4263001	Penalties	2.03	-	-	-	-	-	72,695.76
		4263003	Penalties - Quality of Service	-	-	-	-	-	-	114,189.27
	4263 Total			**2.03**	**-**	**-**	**-**	**-**	**-**	**186,885.03**
										-
4264	**Civic & Political Activities**	4264000	Civic and Political Activity	125,908.14	99,285.00	99,301.00	99,339.00	99,397.00	99,467.00	1,093,721.72
		4264001	Non-deduct Lobbying per IRS	15,194.59	-	-	-	-	-	41,681.44
	4264 Total			**141,102.73**	**99,285.00**	**99,301.00**	**99,339.00**	**99,397.00**	**99,467.00**	**1,135,403.16**
										-
4265	**Other Deductions**	4265001	Other Deductions - Associated	-	-	-	-	-	-	-
		4265002	Other Deductions - Nonassoc	96,130.61	1,435.00	935.00	435.00	435.00	444.00	602,845.17
		4265004	Social & Service Club Dues	9,657.11	5,371.00	5,518.00	5,371.00	5,371.00	5,521.00	89,699.20
		4265006	Shutdown Coal Company Exp	-	2,769,537.00	-	-	-	-	2,769,537.00

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Southerwestern Electric Power Company
Trial Balance - Income Statement
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger sub fiscal or calendar years. Also, provide monthly trial balances fo

FERC	FERC Title	Account	Description	7/31/2018	8/31/2018	9/30/2018	10/31/2018	11/30/2018	12/31/2018	Test Year Total
		4265007	Regulatory Expenses	5,000.50	1,962.00	2,015.00	1,962.00	1,962.00	2,016.00	32,761.96
		4265009	Factored Cust A/R Exp - Affil	526,832.07	522,958.00	482,071.00	464,439.00	420,413.00	404,455.00	5,183,895.76
		4265010	Fact Cust A/R-Bad Debts-Affil	364,467.64	359,122.00	331,044.00	318,935.00	288,702.00	277,744.00	3,559,842.79
		4265033	Transition Costs	601.48	-	-	-	-	-	1,065.54
		4265038	Wind Catcher Project Expenses	2,565,061.73	-	-	-	-	-	24,771,944.39
	4265 Total			**3,567,751.14**	**3,660,385.00**	**821,583.00**	**791,142.00**	**716,883.00**	**690,180.00**	**37,011,591.81**
										-
4270	**Interest on Long -Term Debt**	4270002	Int on LTD - Install Pur Contr	71,333.33	71,333.00	71,333.00	71,334.00	71,334.00	71,334.00	1,584,039.11
		4270005	Int on LTD - Other LTD	333,848.80	-	-	-	-	-	2,135,990.19
		4270006	Int on LTD - Sen Unsec Notes	8,616,679.39	9,273,724.00	10,476,952.00	10,931,345.00	9,128,119.00	9,128,119.00	111,181,888.45
	4270 Total			**9,021,861.52**	**9,345,057.00**	**10,548,285.00**	**11,002,679.00**	**9,199,453.00**	**9,199,453.00**	**114,901,917.75**
										-
4280	**Amrtz Debt Dscnt & Exp**	4280002	Amrtz Debt Dscnt&Exp-Instl Pur	2,804.65	7,972.00	10,694.00	10,694.00	10,694.00	10,694.00	121,574.71
		4280003	Amrtz Debt Dscnt&Exp-N/P		-	-	-	-	-	-
		4280006	Amrtz Dscnt&Exp-Sn Unsec Note	129,592.88	107,686.00	144,443.00	144,443.00	144,444.00	144,443.00	1,642,127.55
	4280 Total			**132,397.53**	**115,658.00**	**155,137.00**	**155,137.00**	**155,138.00**	**155,137.00**	**1,763,702.26**
										-
4281	**Amrtz Loss on Reacquird Debt**	4281001	Amrtz Loss Rcquired Debt-FMB	17,208.45	7,822.00	7,822.00	7,822.00	7,822.00	7,822.00	159,569.14
		4281002	Amrtz LossRcquired Debt-IPC	4,088.56	4,543.00	4,543.00	4,543.00	4,543.00	4,543.00	92,677.36
		4281004	Amrtz Loss Rcquired Debt-Dbnt	19,656.97	8,935.00	8,935.00	8,935.00	8,935.00	8,935.00	182,273.77
	4281 Total			**40,953.98**	**21,300.00**	**21,300.00**	**21,300.00**	**21,300.00**	**21,300.00**	**434,520.27**
										-
4291	**Amrtz Gain Rcqred Debt-Cr**	4291001	Amrtz Gain Rcqred Debt-Cr-FMB	(925.96)	-	-	-	-	-	(6,481.71)
	4291 Total			**(925.96)**	**-**	**-**	**-**	**-**	**-**	**(6,481.71)**
										-
4300	**Int to Associated Companies**	4300003	Int to Assoc Co - CBP	252,156.30	113,671.00	113,671.00	-	-	10,159.00	2,016,749.68
	4300 Total			**252,156.30**	**113,671.00**	**113,671.00**	**-**	**-**	**10,159.00**	**2,016,749.68**
										-
4310	**Other Interest Expense**	4310001	Other Interest Expense	298,820.42	132,870.00	133,470.00	134,180.00	134,828.00	135,484.00	1,731,959.66
		4310002	Interest on Customer Deposits	159,311.23	148,404.00	143,913.00	148,018.00	143,834.00	152,033.00	1,805,178.27
		4310007	Lines Of Credit	56,668.95	6,255.00	5,564.00	9,113.00	9,594.00	8,688.00	390,220.12
		4310014	Other Interest - Fuel Recovery	-	5,000.00	5,000.00	5,000.00	5,000.00	5,000.00	25,000.00
		4310017	Mine Reclamation Interest	186,522.28	159,603.00	160,324.00	161,177.00	161,956.00	162,744.00	2,080,429.30
		4310023	Interest Expense - State Tax	-	-	-	-	-	-	90,660.00
	4310 Total			**701,322.88**	**452,132.00**	**448,271.00**	**457,488.00**	**455,212.00**	**463,949.00**	**6,123,447.35**
										-
4320	**Allw Brrwed Fnds Used Cnstr-Cr**	4320000	Allw Brrwed Fnds Used Cnstr-Cr	(386,243.51)	(610,124.00)	(552,484.00)	(623,859.00)	(633,203.00)	(559,729.00)	(6,222,224.58)
	4320 Total			**(386,243.51)**	**(610,124.00)**	**(552,484.00)**	**(623,859.00)**	**(633,203.00)**	**(559,729.00)**	**(6,222,224.58)**
	Net (Income)/Loss			**(32,135,752.13)**	**(26,415,377.00)**	**(24,471,718.00)**	**(2,741,114.00)**	**19,815.00**	**(11,480,590.00)**	**(146,664,905.62)**

Southerwestern Electric Power Company
Trial Balance - Balance Sheet
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

FERC	FERC Title	Account	Description	Balance 12/31/16	Balance 12/31/17	Actual Balance 1/31/18	Balance 2/28/18	Balance 3/31/18	Balance 4/30/18	Balance 5/31/18
1010	**Plant In Service**	1010001	Plant in Service	7,668,397,690.29	7,878,728,870.35	7,917,841,532.24	7,932,070,838.87	7,934,836,958.86	7,949,159,383.35	8,357,776,585.92
		1010006	Dolet Hills FAS 143 ARO Asset	11,477,844.20	16,208,616.91	16,208,616.91	16,208,616.91	16,209,810.21	16,209,807.52	16,208,616.91
	1010 Total			**7,679,875,534.49**	**7,894,937,487.26**	**7,934,050,149.15**	**7,948,279,455.78**	**7,951,046,769.07**	**7,965,369,190.87**	**8,373,985,202.83**
1011	**Property Under Capital Leases**	1011001	Capital Leases	47,522,935.42	46,795,157.94	46,519,232.72	46,630,626.49	46,795,922.23	48,188,293.22	48,735,660.43
		1011006	Prov-Leased Assets	(19,124,966.38)	(20,022,232.13)	(20,062,009.89)	(20,239,962.92)	(20,585,336.36)	(20,927,957.66)	(21,291,117.97)
		1011012	Accrued Capital Leases	100,562.71	62,863.73	124,415.79	141,803.30	1,379,274.11	466,558.51	160,929.74
	1011 Total			**28,498,531.75**	**26,835,789.54**	**26,581,638.62**	**26,532,466.87**	**27,589,859.98**	**27,726,894.07**	**27,605,472.20**
1050	**Plant Held for Future Use**	1050001	Held For Fut Use	1,271,700.47	1,271,700.47	1,271,700.47	1,271,700.47	1,271,700.47	1,271,700.47	1,271,700.47
	1050 Total			**1,271,700.47**	**1,271,700.47**	**1,271,700.47**	**1,271,700.47**	**1,271,700.47**	**1,271,700.47**	**1,271,700.47**
1060	**Completed Const Not Classifd**	1060001	Const Not Classifd	926,851,543.30	946,430,378.91	926,069,146.60	921,422,446.40	956,266,455.58	949,507,776.84	622,215,732.70
	1060 Total			**926,851,543.30**	**946,430,378.91**	**926,069,146.60**	**921,422,446.40**	**956,266,455.58**	**949,507,776.84**	**622,215,732.70**
1070	**Construction Work In Progress**	1070001	CWIP - Project	113,703,336.58	220,763,745.13	241,332,979.49	265,995,478.78	258,772,095.21	285,647,889.82	227,032,124.93
	1070 Total			**113,703,336.58**	**220,763,745.13**	**241,332,979.49**	**265,995,478.78**	**258,772,095.21**	**285,647,889.82**	**227,032,124.93**
1080	**Accum Prov for Deprec of Plant**	1080001	A/P for Deprec of Plt	(2,355,568,719.38)	(2,453,707,899.85)	(2,465,507,097.81)	(2,477,202,432.36)	(2,486,910,997.76)	(2,499,044,494.39)	(2,507,488,985.17)
		1080005	RWIP - Project Detail	13,703,710.37	12,434,633.39	11,731,157.08	11,896,100.87	12,854,031.94	13,620,960.12	11,599,040.61
		1080011	Cost of Removal Reserve	(415,433,208.41)	(430,814,148.25)	(431,410,437.40)	(432,818,799.11)	(433,451,655.09)	(435,175,182.60)	(435,161,673.77)
		1080012	Dolet Hills FAS 143 ARO Deprec	(5,992,439.00)	(6,380,547.77)	(6,423,465.08)	(6,466,382.36)	(6,509,299.73)	(6,552,217.08)	(6,595,134.37)
		1080013	ARO Removal Deprec - Accretion	5,699,336.93	6,355,203.37	6,414,650.84	6,474,323.74	6,534,132.36	6,594,101.22	6,654,207.83
		1080155	Unrecovered Plant	75,420,280.72	50,276,783.68	50,276,783.68	50,276,783.68	50,276,783.68	50,276,783.68	50,276,783.68
	1080 Total			**(2,682,171,038.77)**	**(2,821,835,975.43)**	**(2,834,918,408.69)**	**(2,847,840,405.54)**	**(2,857,207,004.60)**	**(2,870,280,049.05)**	**(2,880,715,761.19)**
1110	**A/P for Amortization of Plant**	1110001	A/P for Amort of Plt	(30,989,468.76)	(42,327,848.22)	(43,651,274.93)	(44,994,137.00)	(45,771,336.49)	(47,151,812.08)	(48,551,314.46)
	1110 Total			**(30,989,468.76)**	**(42,327,848.22)**	**(43,651,274.93)**	**(44,994,137.00)**	**(45,771,336.49)**	**(47,151,812.08)**	**(48,551,314.46)**
1140	**Plant Acquisition Adjustments**	1140001	Plant Acquisition Adj	18,043,976.22	18,043,976.22	18,043,976.22	18,043,976.22	18,043,976.22	18,043,976.22	18,043,976.22
	1140 Total			**18,043,976.22**	**18,043,976.22**	**18,043,976.22**	**18,043,976.22**	**18,043,976.22**	**18,043,976.22**	**18,043,976.22**
1150	**Amrtz of Plant Acquisition Adj**	1150001	Amrtz of Plt Acqt Adj	(18,043,976.22)	(18,043,976.22)	(18,043,976.22)	(18,043,976.22)	(18,043,976.22)	(18,043,976.22)	(18,043,976.22)
	1150 Total			**(18,043,976.22)**	**(18,043,976.22)**	**(18,043,976.22)**	**(18,043,976.22)**	**(18,043,976.22)**	**(18,043,976.22)**	**(18,043,976.22)**
1160	**Other Plant Adjustments**	1160007	OthElecPltAdjTurkImprmnt-EPIS	(58,411,747.11)	(58,411,747.11)	(58,411,747.11)	(58,411,747.11)	(58,411,747.11)	(58,411,747.11)	(58,411,747.11)
		1160008	TurkAFUDCReverseTXCap-EPIS	(1,313,076.50)	(1,313,076.50)	(1,313,076.50)	(1,313,076.50)	(1,313,076.50)	(1,313,076.50)	(1,313,076.50)
		1160009	AmortTurkImprmnt&AFUDCReversal	4,375,672.88	5,460,950.36	5,551,390.15	5,641,829.94	5,732,269.73	5,822,709.52	5,913,149.31
		1160012	Turk Imprmnt-AuxBoiler	(2,282,304.00)	(18,500,000.00)	(18,500,000.00)	(18,500,000.00)	(18,500,000.00)	(18,500,000.00)	(18,500,000.00)
		1160013	Turk Imprmnt-AuxBoiler Amort	180,804.28	1,760,696.00	1,792,146.00	1,823,596.00	1,855,046.00	1,886,496.00	1,917,946.00
		1160016	TX Trans Veg Mgmt Cost Wrteoff		(1,194,842.07)	(1,236,964.30)	(1,242,439.67)	(1,267,135.29)	(1,326,055.84)	(1,364,925.45)
		1160017	TX Distr Veg Mgmt Cost Wrteoff		(4,127,853.33)	(4,103,577.10)	(4,103,577.10)	(4,103,577.10)	(4,103,577.10)	(4,103,577.10)
		1160018	TX Dist Veg Mgt WriteOff Amort		246,068.51	255,209.54	264,404.97	273,600.40	282,795.83	291,991.26
		1160019	TX Tran Veg Mgt WriteOff Amort		46,766.11	48,650.60	50,497.69	52,381.50	54,352.90	56,382.09
		1160020	TX Trans Costs - SERP		(510,536.06)	(159,251.17)	(159,248.12)	(159,418.38)	(159,475.73)	(159,518.51)
		1160021	TX Distr Costs - SERP		(231,793.77)	(47,623.17)	(47,627.73)	(47,701.25)	(47,726.26)	(47,749.36)
		1160022	TX Gen Costs - SERP		(5,901,516.59)	(303,139.04)	(302,754.79)	(302,506.81)	(302,144.64)	(301,778.86)
		1160023	TX CWIP FinBased Incen - Trans			(1,613,516.76)	(1,632,905.51)	(1,652,240.34)	(1,675,118.41)	(1,692,898.21)
		1160024	TX CWIP FinBased Incen - Distr			(2,004,879.78)	(2,020,409.09)	(2,033,856.93)	(2,054,354.53)	(2,056,392.50)
		1160025	TX CWIP FinBased Incen - Gen			(2,387,108.55)	(2,410,257.31)	(2,419,603.46)	(2,432,079.20)	(2,440,168.53)
		1160026	TX RWIP FinBased Incen - Trans			(62,412.96)	(62,905.96)	(63,094.97)	(63,276.17)	(63,459.68)
		1160027	TX RWIP FinBased Incen - Distr			(79,404.55)	(80,309.06)	(80,859.80)	(82,389.57)	(81,622.73)
		1160028	TX RWIP FinBased Incen - Gen			(93,023.90)	(93,160.23)	(93,506.64)	(93,921.63)	(93,894.73)
	1160 Total			**(57,450,650.45)**	**(82,676,884.45)**	**(82,668,328.60)**	**(82,600,089.58)**	**(82,535,026.95)**	**(82,518,588.44)**	**(82,451,340.61)**
1210	**Nonutility Property**	1210001	Nonutility Property - Owned	3,251,146.77	297,694.16	297,694.16	297,694.16	297,694.16	297,694.16	297,694.16
		1210003	Nonutility Property - WIP		2.10	2.10	2.10	2.10	2.10	2.10
	1210 Total			**3,251,146.77**	**297,696.26**	**297,696.26**	**297,696.26**	**297,696.26**	**297,696.26**	**297,696.26**
1220	**Depr & Amort of Nonutil Prop**	1220001	Depr&Amrt of Nonutl Prop-Ownd	(0.01)	2,418,433.09	2,418,433.09	2,418,433.09	(0.01)	64.55	64.55
		1220003	Depr&Amrt of Nonutl Prop-WIP	20,734.30	(1,791,259.00)	(1,791,045.15)	(2,418,433.10)	64.56	0.00	0.00

Southerwestern Electric Power Company
Trial Balance - Balance Sheet
Test Year Ending December 31, 2018
Docket No. 19-008-U

Schedule E-17B

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

FERC	FERC Title	Account	Description	Balance 12/31/16	Balance 12/31/17	Actual Balance 1/31/18	Balance 2/28/18	Balance 3/31/18	Balance 4/30/18	Balance 5/31/18
	1220 Total			**20,734.29**	**627,174.09**	**627,387.94**	**(0.01)**	**64.55**	**64.55**	**64.55**
1231	**Invest in Subsidiary Companies**	1230000	Invest Nonconsol Assoc Co		-	-	-	-	-	-
		1231003	Capital Contributions to Subs	100,000.00	100,000.00	100,000.00	100,000.00	100,000.00	100,000.00	100,000.00
		1231005	Invest in Subs Retained Erngs	1,857,123.15	1,873,774.39	1,874,852.87	1,877,021.03	1,879,767.80	1,882,977.60	1,885,951.36
		1231101	Invest Nonconsol Subs-Equity	25,044,703.18	24,759,406.87	24,759,406.87	24,759,406.87	24,759,406.87	24,759,406.87	24,759,406.87
		1231102	Equity in Erngs Nonconsol Subs	16,158,514.57	12,324,476.97	12,537,913.90	12,708,700.88	12,856,651.75	13,006,661.45	13,206,851.97
	1231 Total			**43,160,340.90**	**39,057,658.23**	**39,272,173.64**	**39,445,128.78**	**39,595,826.42**	**39,749,045.92**	**39,952,210.20**
1240	**Other Investments**	1240002	Oth Investments-Nonassociated	878,008.64	878,008.64	878,008.64	878,008.64	878,008.64	878,008.64	878,008.64
		1240027	Other Property - RWIP			-	-	129.11	1,251.23	1,896.29
		1240029	Other Property - CPR	301,443.53	301,443.53	301,443.53	301,443.53	301,443.53	301,443.53	301,443.53
	1240 Total			**1,179,452.17**	**1,179,452.17**	**1,179,452.17**	**1,179,452.17**	**1,179,581.28**	**1,180,703.40**	**1,181,348.46**
1290	**Special Funds**	1290001	Non-UMWA PRW Funded Position	9,874,156.28	30,137,864.41	30,137,864.41	30,137,864.41	28,996,881.16	28,996,881.16	28,996,881.16
		1290002	SFAS 106 - Non-UMWA PRW			603,943.59	1,207,887.18	1,815,174.00	2,391,866.58	2,996,924.59
	1290 Total			**9,874,156.28**	**30,137,864.41**	**30,741,808.00**	**31,345,751.59**	**30,812,055.16**	**31,388,747.74**	**31,993,805.75**
1310	**Cash**	1310000	Cash	1,626,028.50	1,642,739.42	1,856,638.21	2,332,530.19	719,646.45	2,042,467.92	1,550,389.84
	1310 Total			**1,626,028.50**	**1,642,739.42**	**1,856,638.21**	**2,332,530.19**	**719,646.45**	**2,042,467.92**	**1,550,389.84**
1340	**Other Special Deposits**	1340018	Spec Deposits - Elect Trading	(0.01)	100,252.23	100,303.24	100,097.06	100,148.07	100,049.38	100,132.16
		1340046	Deposits-O&M Dolet Hills Plant	2,842,000.00	2,807,000.00	5,087,000.00	10,195,000.00	6,774,380.58	6,774,380.58	5,317,898.48
		1340048	Spec Deposits-Trading Contra	108,346.00		-	570,348.00	46,320.00	13,293.00	95,593.00
		1340050	Spec Deposit Mizuho Securities	0.20						
		1340051	Spec Depost RBC	2,236.44	22,782.86	46,907.85	-	-	37,627.95	-
		1340053	Deposits - Flexible Spending	36,814.42	90,164.07	90,164.07	90,164.07	90,164.07	90,164.07	90,164.07
	1340 Total			**2,989,397.06**	**3,020,199.16**	**5,324,375.16**	**10,955,609.13**	**7,011,012.72**	**7,015,514.98**	**5,603,787.71**
1420	**Customer Accounts Receivable**	1420001	Customer A/R - Electric	88,780,194.54	93,936,702.43	110,597,053.18	109,408,163.17	93,996,288.11	92,063,041.30	99,140,232.68
		1420006	A/R-Customer Assistance	200.00		1,089.00	557.00	-	-	-
		1420014	Customer A/R-System Sales	19,415,339.94	17,158,587.51	17,488,404.59	12,887,925.39	14,309,717.91	17,302,742.70	18,712,331.11
		1420022	Cust A/R - Factored	(84,688,375.35)	(94,050,316.69)	(117,710,690.72)	(107,684,048.83)	(90,606,597.03)	(84,558,948.08)	(101,267,471.62)
		1420023	Cust A/R-System Sales - MLR	-		-	-	-	-	103,628.34
		1420044	Customer A/R - Estimated	2,139,793.00	33,572,378.78	37,292,697.65	37,121,089.28	34,004,943.50	31,135,456.25	27,658,142.71
		1420048	Emission Allowance Trading	-	700.00	-	-	-	-	-
		1420051	MISO AR Accrual	125,586.97		-	-	325,676.87	-	-
		1420055	SPP AR Accrual	13,306,119.35	7,263,317.52	8,385,754.45	5,062,063.84	9,079,188.25	1,998,867.46	2,477,838.79
		1420101	Other Accounts Rec - Cust	242,382.73	271,979.14	338,099.00	342,318.02	547,515.07	258,314.03	465,362.41
		1420102	AR Peoplesoft Billing - Cust	7,574,482.76	11,079,730.54	11,526,316.23	7,036,218.46	3,847,805.93	3,092,280.88	2,866,987.95
	1420 Total			**46,895,723.94**	**69,233,079.23**	**67,918,723.38**	**64,174,286.33**	**65,504,538.61**	**61,291,754.54**	**50,157,052.37**
1430	**Other Accounts Receivable**	1430002	Allowances	39.85	24.07	24.07	24.07	24.07	24.07	105.72
		1430022	2001 Employee Biweekly Pay Cnv	7,628.97	7,628.97	7,628.97	7,628.97	7,628.97	7,628.97	7,628.97
		1430080	Jointly Owned Unit O&M Billing	14,315,228.58	22,896,433.91	19,124,560.55	18,283,976.34	9,885,846.97	10,078,702.58	10,026,213.27
		1430081	Damage Recovery - Third Party	50,032.78	70,264.49	103,333.49	70,004.04	78,947.04	26,115.00	49,114.20
		1430083	Damage Recovery Offset Demand	(50,032.78)	(70,264.49)	(111,446.49)	(82,646.04)	(78,947.04)	(31,926.00)	(57,267.00)
		1430086	AR Accrual NYMEX OTC Penults	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		1430101	Other Accounts Rec - Misc	244,390.71	1,410,840.26	1,512,171.63	1,394,085.35	1,201,952.43	1,692,052.59	1,656,657.53
		1430102	AR Peoplesoft Billing - Misc	1,792,731.43	1,099,426.13	2,732,625.13	1,963,839.47	957,943.87	2,938,763.26	2,326,136.59
		1430103	AR Long-Term-Miscellaneous		1,386,715.49	1,317,379.72	1,248,043.95	1,178,708.18	1,109,372.41	1,040,036.64
	1430 Total			**16,360,019.54**	**26,801,068.83**	**24,686,277.07**	**22,884,956.15**	**13,232,104.49**	**15,820,732.88**	**15,048,625.92**
1440	**A/P for Uncollectible Accts-Cr**	1440002	Uncoll Accts-Other Receivables	(1,255,463.17)	(1,329,448.12)	(1,235,045.75)	(793,580.98)	(557,714.93)	(557,714.93)	(557,714.93)
	1440 Total			**(1,255,463.17)**	**(1,329,448.12)**	**(1,235,045.75)**	**(793,580.98)**	**(557,714.93)**	**(557,714.93)**	**(557,714.93)**
1450	**Corp Borrow Prg (NR-Assoc)**	1450000	Corp Borrow Prg (NR-Assoc)	167,816,846.84		287,581,426.00	230,675,815.89	-	-	-
	1450 Total			**167,816,846.84**	**-**	**287,581,426.00**	**230,675,815.89**	**-**	**-**	**-**
1460	**Accts Rec from Assoc Cos**	1460001	A/R Assoc Co - InterUnit G/L	20,845,984.70	19,785,079.10	20,937,166.50	37,512,609.40	12,771,236.51	12,129,654.01	23,132,654.82
		1460004	A/R Assoc Co - CM Bills	54,422.38	90,718.31	23,274.90	31,735.81	105,027.76	79,899.23	79,998.95
		1460006	A/R Assoc Co - Intercompany	449,671.45	239,972.83	207,098.25	245,509.70	369,406.43	142,364.31	222,096.26

Southwestern Electric Power Company
Trial Balance - Balance Sheet
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

FERC	FERC Title	Account	Description	Balance 12/31/16	Balance 12/31/17	Actual Balance 1/31/18	Balance 2/28/18	Balance 3/31/18	Balance 4/30/18	Balance 5/31/18
		1460009	A/R Assoc Co - InterUnit A/P	50,286.00	10,033.31	8,064.32	756.11	0.00	1,506.41	15,736.96
		1460011	A/R Assoc Co - Multi Pmts	5,261,520.99	7,323,850.93	7,214,830.04	6,742,711.98	2,167,042.41	2,315,088.69	6,462,191.39
		1460025	Fleet - M4 - A/R	22,654.57	20,176.90	19,848.31	20,469.52	(0.00)	59,484.70	53,449.84
	1460 Total			**26,684,540.09**	**27,469,831.38**	**28,410,282.32**	**44,553,792.52**	**15,412,713.11**	**14,727,997.35**	**29,966,128.22**
1510	**Fuel Stock**	1510001	Fuel Stock - Coal	40,458,465.73	34,666,066.76	33,988,571.25	42,529,259.71	45,594,973.80	42,225,808.79	45,280,782.31
		1510002	Fuel Stock - Oil	4,099,359.24	4,351,690.98	4,274,571.78	4,056,312.94	3,806,642.50	3,725,072.78	4,005,867.29
		1510016	Coal Inv on Hand Transp	10,698.27	18,661.59	12,605.24	8,540.83	24,087.86	4,778.91	9,916.18
		1510017	Lignite Inv on Hand Inc Transp	22,905,755.53	41,872,525.19	35,288,679.66	29,292,590.95	28,824,014.46	30,116,756.94	30,399,366.65
		1510018	Coal Survey Adjustment	1,494,282.82	(886,900.91)	(40,625.60)	(131,175.43)	(221,725.25)	-	(1,535,489.15)
		1510020	Fuel Stock Coal - Intransit	1,616,924.77	552,606.13	3,169,108.93	2,690,188.71	2,783,644.70	942,095.77	2,760,812.46
	1510 Total			**70,585,486.36**	**80,574,649.74**	**76,692,911.25**	**78,445,717.71**	**80,811,638.07**	**77,014,513.18**	**80,921,255.74**
1520	**Fuel Stock Exp Undistributed**	1520000	Fuel Stock Exp Undistributed	2,186,949.85	1,502,762.16	1,467,232.58	1,620,283.02	1,892,780.89	2,184,330.09	2,473,646.03
	1520 Total			**2,186,949.85**	**1,502,762.16**	**1,467,232.58**	**1,620,283.02**	**1,892,780.89**	**2,184,330.09**	**2,473,646.03**
1540	**Materials & Oper Supplies**	1540001	M&S - Regular	66,585,413.01	65,997,476.67	65,662,848.96	65,769,789.60	66,012,510.76	65,754,003.71	65,867,540.06
		1540004	M&S - Exempt Material	566,029.70	573,204.33	577,703.19	589,867.84	562,782.49	559,748.53	509,279.02
		1540006	M&S - Lime and Limestone	652,258.36	708,002.06	959,849.05	1,965,266.61	1,667,960.42	1,470,547.24	1,048,897.37
		1540013	Transportation Inventory	68,544.11	62,747.80	62,747.80	62,747.80	62,747.80	87,065.69	87,065.69
		1540025	Matls Supply-Activated Carbon	450,051.89	413,621.60	470,343.52	387,157.17	261,470.11	329,289.92	425,338.43
		1540028	M&S - Anhydrous Ammonia	31,248.18	13,042.02	31,690.80	17,840.26	28,753.29	2,765.61	43,828.01
		1540030	Matls Supply-Calcium Bromide	48,654.20	54,838.83	65,857.03	58,863.25	52,355.65	51,237.16	56,524.16
	1540 Total			**68,402,199.45**	**67,822,933.31**	**67,831,040.35**	**68,851,532.53**	**68,648,580.52**	**68,254,657.86**	**68,038,472.74**
1581	**Allowance Inventory**	1581012	CSAPR An. NOx Inv. - Current	1,914.68	1,918.74	-	-	-	-	-
		1581014	CSAPR Seas NOx Comp Inv - Curr	26,394.72	88,089.16	88,089.16	88,402.63	126,502.63	126,502.63	105,009.89
	1581 Total			**28,309.40**	**90,007.90**	**88,089.16**	**88,402.63**	**126,502.63**	**126,502.63**	**105,009.89**
1630	**Stores Expense Undistributed**	1630004	Strs Exp-T&D Satellite Storerm			-	-	-	-	0.00
		1630056	Knox Lee Power Plant			-	-	-	-	-
		1630059	Pirkey Power Plant			-	-	-	-	(0.00)
		1630061	Welsh Power Plant			-	-	-	-	0.01
	1630 Total			**-**	**-**	**-**	**-**	**-**	**-**	**0.00**
1650	**Prepayments**	1650001	Prepaid Insurance	1,492,530.41	1,377,548.65	1,158,305.16	939,061.67	735,862.58	516,882.60	594,525.40
		165000218	Prepaid Taxes			899,065.88	449,532.94	-	998,958.50	499,479.25
		1650005	Prepaid Employee Benefits	254,500.00		43,126.14	43,950.50	-	-	-
		1650006	Other Prepayments	16,223,254.02	16,474,492.30	16,806,557.02	17,512,052.84	16,349,332.78	17,307,667.91	17,144,149.12
		1650009	Prepaid Carry Cost-Factored AR	118,299.43	129,132.50	237,046.16	167,813.48	128,606.80	172,566.72	171,563.56
		1650010	Prepaid Pension Benefits	95,599,076.29	95,630,493.29	94,919,108.29	94,207,723.29	93,601,553.79	92,925,240.63	92,248,927.47
		165000218	Prepaid Taxes							
		165001116	Prepaid Sales Taxes	873,400.00						
		165001117	Prepaid Sales Taxes		803,600.00	-	(1,800,069.60)	-	-	-
		165001118	Prepaid Sales Taxes			875,000.00	3,445,504.40	720,400.00	737,200.00	1,848,450.62
		165001216	Prepaid Use Taxes	213.86						
		165001217	Prepaid Use Taxes		20,086.86	-	-	-	-	-
		165001218	Prepaid Use Taxes			21,847.66	1,643.33	1,261.02	8,325.32	266.57
		165001316	Prepaid Local Franchise Taxes	64,299.79						
		165001317	Prepaid Local Franchise Taxes		57,864.77	-	-	-	-	-
		165001318	Prepaid Local Franchise Taxes			57,118.97	56,563.67	56,085.32	55,606.29	55,052.65
		1650014	FAS 158 Qual Contra Asset	(95,599,076.29)	(95,630,493.29)	(94,919,108.29)	(94,207,723.29)	(93,601,553.79)	(92,925,240.63)	(92,248,927.47)
		1650016	FAS 112 ASSETS		-	-	-	-	-	-
		1650017	Prepayment - Coal	11,371,800.00	9,075,000.00	10,188,116.99	7,047,221.71	4,303,349.94	3,344,003.52	4,616,210.78
		1650018	Affl Trans Intercon Providers	-	(0.00)	0.00	0.00	0.00	0.00	0.00
		1650021	Prepaid Insurance - EIS	920,549.15	980,733.55	930,559.73	653,146.01	1,819,034.34	1,534,360.37	1,249,686.40
		1650023	Prepaid Lease	141,110.59	199,883.68	185,583.68	171,283.68	192,983.68	178,683.68	212,383.68
		1650029	Future Wetlands Credits L-T	300,000.00	300,000.00	300,000.00	300,000.00	300,000.00	300,000.00	300,000.00
		1650030	Other Prepayments - Long Term	5,093,404.95		618,643.39	618,643.39	618,643.39	1,709,806.12	1,709,806.12
		1650035	PRW Without MED-D Benefits	18,816,754.28	23,527,840.41	24,131,784.00	24,735,727.59	25,343,014.41	25,919,706.99	26,524,765.00
		1650037	FAS158 Contra-PRW Exclud Med-D	(18,816,754.28)	(23,527,840.41)	(24,131,784.00)	(24,735,727.59)	(25,343,014.41)	(25,919,706.99)	(26,524,765.00)
	1650 Total			**36,853,362.20**	**29,418,342.31**	**32,320,970.78**	**29,606,348.02**	**25,225,559.85**	**26,864,061.03**	**28,401,574.15**

Southerwestern Electric Power Company
Trial Balance - Balance Sheet
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

Schedule E-17B

					Actual					
FERC	FERC Title	Account	Description	Balance 12/31/16	Balance 12/31/17	Balance 1/31/18	Balance 2/28/18	Balance 3/31/18	Balance 4/30/18	Balance 5/31/18
1710	**Interest&Dividends Receivable**	1710010	Interest Under Recover - LA	1,809.00						
		1710048	Interest Receivable -FIT -LT	38,240.00	1,691.00	1,691.00	1,691.00	1,918.00	1,918.00	1,918.00
		1710348	Interest Receivable -SIT -LT	107,153.00						
	1710 Total			**147,202.00**	**1,691.00**	**1,691.00**	**1,691.00**	**1,918.00**	**1,918.00**	**1,918.00**
1720	**Rents Receivable**	1720000	Rents Receivable	1,559,250.13	1,592,143.41	743,125.65	895,440.19	443,401.12	595,140.32	746,892.76
	1720 Total			**1,559,250.13**	**1,592,143.41**	**743,125.65**	**895,440.19**	**443,401.12**	**595,140.32**	**746,892.76**
1730	**Accrued Utility Revenues**	1730003	Acrd Utility Rev-West	26,392,267.85	35,186,615.49	32,163,348.63	26,468,804.84	24,599,040.53	27,466,258.83	55,255,000.49
	1730 Total			**26,392,267.85**	**35,186,615.49**	**32,163,348.63**	**26,468,804.84**	**24,599,040.53**	**27,466,258.83**	**55,255,000.49**
1740	**Misc Current & Accrued Assets**	1740000	Misc Current & Accrued Assets	0.00		-	-	81,201.55	-	-
	1740 Total			**0.00**	**-**	**-**	**-**	**81,201.55**	**-**	**-**
1750	**Curr. Unreal Gains - NonAffil**	1750001	Curr. Unreal Gains - NonAffil	1,040,606.21	6,395,724.77	5,221,774.72	4,803,350.05	1,761,863.34	1,735,412.42	3,105,084.96
		1750002	Long-Term Unreal Gns - Non Aff	(0.00)		-	-	-	15,301.00	42,021.00
		1750021	S/T Asset MTM Collateral	(108,346.00)		-	(570,348.00)	(46,320.00)	(12,188.00)	(83,482.00)
		1750022	L/T Asset MTM Collateral			-	-	-	(1,105.00)	(12,111.00)
	1750 Total			**932,260.21**	**6,395,724.77**	**5,221,774.72**	**4,233,002.05**	**1,715,543.34**	**1,737,420.42**	**3,051,512.96**
1810	**Unamortized Debt Expense**	1810002	Unamort Debt Exp - Inst Pur Cn	251,036.96	65,883.44	50,453.98	35,024.52	32,219.87	29,415.22	26,610.57
		1810003	Unamort Debt Exp Notes Payable	63,366.22	288,376.69	278,748.40	269,120.11	259,491.82	249,863.53	240,235.24
		1810006	Unamort Debt Exp - Sr Unsec Nt	11,062,353.14	10,018,988.77	14,203,859.77	14,087,480.70	14,079,393.55	13,991,101.99	14,134,301.93
		1810102	Unamort Debt Exp-PCB Ins	63,656.96	25,944.54	12,623.38	-	-	-	-
	1810 Total			**11,440,413.28**	**10,399,193.44**	**14,545,685.53**	**14,391,625.33**	**14,371,105.24**	**14,270,380.73**	**14,401,147.73**
1823	**Other Regulatory Assets**	1823000	Other Regulatory Assets	1,066,473.00	181,703.00	155,614.00	131,428.00	123,552.00	112,004.00	98,981.00
		1823010	Energy Efficiency Recovery	2,976,123.80	4,089,562.58	3,383,451.59	2,955,349.52	3,107,405.82	3,489,930.01	3,550,460.15
		1823075	Def Exp Selling Price Variance	(0.00)		-	-	730,747.76	1,071,000.31	2,135,225.94
		1823077	Unreal Loss on Fwd Commitments	261,843.67		-	-	304,954.74	2,786,685.73	717,081.10
		1823099	Asset Retirement Obligations	3,264,625.79	4,489,390.29	4,600,449.88	4,711,784.30	4,823,332.20	4,935,092.17	5,047,046.70
		1823108	Reg Asset - Rate Case Expenses	5,186,768.70	7,016,941.94	6,745,258.33	6,513,744.31	6,421,877.32	6,241,475.03	5,944,541.23
		1823149	Unrecovered Fuel Cost - LA	2,011,153.66		1,236,086.89	3,846,787.16	812,928.13	4,349.00	545,300.89
		1823150	Unrecovered Fuel Cost - AR	6,341,226.97	14,065,695.06	16,224,648.88	16,069,765.20	15,649,771.88	15,411,250.16	17,253,023.49
		1823165	REG ASSET FAS 158 QUAL PLAN	103,231,352.00	96,290,886.00	96,290,886.00	96,290,886.00	95,038,202.25	95,038,202.25	95,038,202.25
		1823166	REG ASSET FAS 158 OPEB PLAN	5,719,489.86	(3,753,348.25)	(3,753,348.25)	(3,753,348.25)	(3,047,164.52)	(3,047,164.52)	(3,047,164.52)
		1823167	REG Asset FAS 158 SERP Plan	625,250.00	1,129,980.00	1,129,980.00	1,129,980.00	1,115,587.25	1,115,587.25	1,115,587.25
		1823180	Deferred Storm Expense	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
		1823219	Under Recovered EAC - LA	221,531.26	246,993.50	69,853.46	98,983.66	145,198.38	-	37,521.76
		1823241	Valley District Due Diligence	231,224.13	33,032.03	16,516.02	-	-	-	-
		1823299	SFAS 106 Medicare Subsidy	4,266,478.39	3,733,168.39	3,688,725.89	3,644,283.39	3,599,840.89	3,555,398.39	3,510,955.89
		1823301	SFAS 109 Flow Thru Defd FIT	141,914,839.20	69,608,874.18	69,594,089.02	69,673,769.73	69,782,112.98	69,752,946.93	69,705,118.82
		1823302	SFAS 109 Flow Thru Defrd SIT	176,520,778.00	189,260,844.00	189,243,085.00	189,238,001.00	191,055,315.00	191,317,110.00	191,354,909.00
		1823306	Net CCS FEED Study Costs	609,357.93	470,074.53	458,467.58	446,858.73	446,858.73	446,858.73	446,858.73
		1823324	LA FRP Asset	117,759.74	175,112.05	167,261.40	159,410.75	151,560.10	143,709.45	135,858.80
		1823348	Louisiana Vegetation Managemnt	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
		1823359	SWEPCo Transmission Recovery	3,068,489.38	3,264,402.55	3,264,402.55	3,264,402.55	3,264,402.55	3,264,402.55	2,992,369.00
		1823360	2010 Severance Costs	1,889,586.58	269,940.70	134,970.21	-	-	-	-
		1823374	Environmental Chemical Cost-AR	1,318,831.66	2,122,776.57	2,213,140.47	2,294,870.19	2,371,933.83	2,387,724.06	2,515,590.13
		1823377	NBV - AROs Retired Plants	512,576.79	508,193.73	507,600.39	507,007.05	506,413.71	505,820.37	505,227.03
		1823424	LA 2015 FRP Asset-SPP Deferral		4,720,151.85	4,720,151.85	4,886,832.56	4,928,512.15	4,970,191.74	5,011,871.33
		1823425	LA 2015 FRP Asset - Contra		(102,864.75)	(102,864.75)	(180,745.40)	(200,219.96)	(219,694.52)	(239,169.08)
		1823428	Welsh 2 TX Portion Undepr Bal		17,576,705.35	17,536,407.13	17,496,013.58	17,455,524.47	17,414,939.57	17,374,258.66
		1823539	Facilities Maint SWEPCO LA	264,100.17	551,611.17	551,548.81	571,358.13	586,813.51	603,637.26	652,503.20
		1823554	WELSH/FLINT CREEK ENVIRONM DEF	17,348,565.00	23,555,541.08	23,418,590.26	23,281,639.44	23,144,688.62	23,007,737.80	22,870,786.98
		1823555	WELSH/FLINTCREEK ENVIR-CONTRA	(6,368,882.00)	(8,239,061.85)	(8,191,160.33)	(8,143,258.81)	(8,095,357.29)	(8,047,455.77)	(7,999,554.25)
	1823 Total			**472,599,543.69**	**431,266,305.71**	**433,303,812.29**	**435,135,802.80**	**434,224,792.51**	**436,261,737.96**	**437,273,391.49**
1830	**Prelimin Surv&Investgtn Chrgs**	1830000	Prelimin Surv&Investgtn Chrgs	838,856.44	1,149,702.59	1,181,848.49	1,178,367.68	1,179,446.06	1,209,300.66	1,327,619.08
	1830 Total			**838,856.44**	**1,149,702.59**	**1,181,848.49**	**1,178,367.68**	**1,179,446.06**	**1,209,300.66**	**1,327,619.08**
1840	**Clearing Accounts**	1840002	Accounts Pay Adj - Clearing			-	-	-	-	(40.00)
		1840019	CMS & CMF - Clearing Activity		(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)

Southerwestern Electric Power Company
Trial Balance - Balance Sheet
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

FERC	FERC Title	Account	Description	Actual						
				Balance 12/31/16	Balance 12/31/17	Balance 1/31/18	Balance 2/28/18	Balance 3/31/18	Balance 4/30/18	Balance 5/31/18
		1840033	Alliance Rail Car - OH	91,866.87	103,523.77	132,154.43	(187,013.33)	258,827.07	(62,165.59)	(8,970.13)
		1840035	IT Oper Company (OPCO) Clearng		(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
	1840 Total			**91,866.87**	**103,523.76**	**132,154.42**	**(187,013.34)**	**258,827.06**	**(62,165.60)**	**(9,010.14)**
1860	**MDD-Internal Billing Only**	1860001	Allowances	1,000.00	123.29	2,042.03	2,042.03	2,142.03	2,042.03	2,042.03
		1860002	Deferred Expenses	4,876,880.92	(260,877.17)	(227,699.51)	(210,195.39)	691.88	(152,232.08)	(130,274.84)
		186000316	Deferred Property Taxes	(0.01)						
		186000318	Deferred Property Taxes			59,504,749.00	54,095,226.00	48,685,703.00	43,276,180.00	37,866,657.00
		1860005	Unidentified Cash Receipts			(1,285.83)	(1,285.83)	-	(486.50)	(486.50)
		1860007	Billings and Deferred Projects	260,111.42	2,364,290.08	3,240,180.40	3,857,528.73	4,916,779.07	5,069,491.91	5,084,328.64
		1860015	Billings Paid Union Benefits			1,374.64	6,570.01	-	2,315.56	8,429.49
		1860046	Railroad Cars Subleased			12,566.00	15,124.00	-	6,787.59	9,345.59
		1860077	Agency Fees - Factored A/R	2,649,127.41	2,764,073.96	3,213,679.61	2,956,074.18	2,612,012.13	2,647,032.77	3,089,794.27
		186008118	Defd Property Tax - Cap Lease			158,583.00	144,166.00	129,749.00	115,332.00	100,915.00
		1860089	Reclamation Advance	11,955,116.35	17,118,863.07	16,828,424.49	16,588,926.54	16,304,767.57	15,546,351.19	14,984,878.04
		1860150	Deferred Rate Case Expense	82,947.88	97,947.89	75,914.74	81,368.89	73,314.89	103,776.89	92,690.39
		1860153	Unamortized Credit Line Fees	714,125.88	497,232.71	468,035.78	453,982.43	455,565.21	441,110.94	401,493.99
		1860154	Affl Deferred Tran(IPP) Credit	-	-	-	-	-	-	-
		1860156	Sabine Mine Rusk Preparation	14,105,748.85	13,793,764.47	13,761,572.85	13,724,956.33	13,670,412.54	13,654,342.13	13,592,925.22
		1860160	Deferred Expenses - Current	111,833.70	109,552.93	515,369.25	151,223.91	141,394.99	145,762.88	239,671.45
		1860166	Def Lease Assets - Non Taxable	270,958.07	235,312.86	235,312.86	-	168,101.24	168,101.24	-
		1860171	Marshall South Mine Prep	45,039.41	17,311.28	14,514.26	12,274.74	10,239.58	(1,112.22)	-
		1860185	Long Term Assoc AR			-	-	-	-	-
	1860 Total			**35,072,889.88**	**36,737,595.36**	**97,803,333.56**	**91,877,982.56**	**87,170,873.12**	**81,024,796.32**	**75,342,409.76**
1890	**Unamrtzd Loss on Recqd Debt**	1890001	Loss Recqd Debt - FMB	2,557,294.03	2,350,792.63	2,333,584.18	2,316,375.73	2,299,167.28	2,281,958.83	2,264,750.39
		1890002	Loss Rec Debt-Ins Purch Cont	525,502.47	228,387.51	203,627.93	178,867.95	174,779.39	170,690.83	166,602.27
		1890004	Loss Rec Debt-Debentures	2,317,335.83	2,081,452.20	2,061,795.23	2,042,138.26	2,022,481.29	2,002,824.32	1,983,167.36
	1890 Total			**5,400,132.33**	**4,660,632.34**	**4,599,007.34**	**4,537,381.94**	**4,496,427.96**	**4,455,473.98**	**4,414,520.02**
1900	**Accum Deferred Income Taxes**	1900011	ADIT Federal Non-UMWA PRW OCI	1,128,087.85	(599,901.90)	(599,901.90)	(599,901.90)	(508,594.00)	(508,594.00)	(508,594.00)
		1900015	ADIT-Fed-Hdg-CF-Int Rate	3,936,677.44	1,897,348.58	1,832,812.85	1,819,905.72	1,781,185.79	1,742,464.37	1,703,742.95
	1900 Total			**5,064,765.29**	**1,297,446.68**	**1,232,910.95**	**1,220,003.82**	**1,272,591.79**	**1,233,870.37**	**1,195,148.95**
1901	**Accum Deferred FIT - Other**	1901001	Accum Deferred FIT - Other	103,664,904.07	95,841,180.32	57,980,022.64	58,150,159.72	56,661,849.32	57,590,452.85	58,809,814.67
		1901002	Accum Deferred SIT - Other	41,963,927.00	47,528,631.06	47,528,631.06	47,528,631.06	48,923,746.89	48,923,746.89	48,923,746.89
	1901 Total			**145,628,831.07**	**143,369,811.38**	**105,508,653.70**	**105,678,790.78**	**105,585,596.21**	**106,514,199.74**	**107,733,561.56**
1902	**Accum Defd FIT - Oth Inc & Ded**	1902001	Accum Defd FIT - Oth Inc & Ded	2,688,777.46	1,619,184.81	1,484,154.82	1,349,124.82	1,214,094.82	1,079,064.82	944,034.82
	1902 Total			**2,688,777.46**	**1,619,184.81**	**1,484,154.82**	**1,349,124.82**	**1,214,094.82**	**1,079,064.82**	**944,034.82**
1903	**Acc Dfd FIT - FAS109 Flow Thru**	1903001	Acc Dfd FIT - FAS109 Flow Thru	65,953,591.22	41,465,204.02	41,429,701.85	41,396,861.54	41,746,724.73	41,769,928.91	41,746,093.95
	1903 Total			**65,953,591.22**	**41,465,204.02**	**41,429,701.85**	**41,396,861.54**	**41,746,724.73**	**41,769,928.91**	**41,746,093.95**
1904	**Accum Dfd FIT - FAS 109 Excess**	1904001	Accum Dfd FIT - FAS 109 Excess	69,706.42	150,046,272.11	150,035,737.78	150,024,573.21	149,344,500.99	149,110,367.20	148,876,233.42
	1904 Total			**69,706.42**	**150,046,272.11**	**150,035,737.78**	**150,024,573.21**	**149,344,500.99**	**149,110,367.20**	**148,876,233.42**
2010	**Common Stock Issued**	2010001	Common Stock Issued-Affiliated	(135,659,520.00)	(135,659,520.00)	(135,659,520.00)	(135,659,520.00)	(135,659,520.00)	(135,659,520.00)	(135,659,520.00)
	2010 Total			**(135,659,520.00)**	**(135,659,520.00)**	**(135,659,520.00)**	**(135,659,520.00)**	**(135,659,520.00)**	**(135,659,520.00)**	**(135,659,520.00)**
2100	**Gain Rsle/Cancl Req Cap Stock**	2100000	Gain Rsle/Cancl Req Cap Stock	(2,106,937.41)	(2,106,937.41)	(2,106,937.41)	(2,106,937.41)	(2,106,937.41)	(2,106,937.41)	(2,106,937.41)
	2100 Total			**(2,106,937.41)**	**(2,106,937.41)**	**(2,106,937.41)**	**(2,106,937.41)**	**(2,106,937.41)**	**(2,106,937.41)**	**(2,106,937.41)**
2110	**Miscellaneous Paid-In Capital**	2110000	Miscellaneous Paid-In Capital	(674,443,763.79)	(674,443,763.79)	(674,443,763.79)	(674,443,763.79)	(674,443,763.79)	(674,443,763.79)	(674,443,763.79)
	2110 Total			**(674,443,763.79)**	**(674,443,763.79)**	**(674,443,763.79)**	**(674,443,763.79)**	**(674,443,763.79)**	**(674,443,763.79)**	**(674,443,763.79)**
2160	**Unappropriatd Retnd Earngs**	2160001	Unapprp Retnd Erngs-Unrstrictd	(1,504,288,277.92)	(1,394,831,221.55)	(1,406,918,019.73)	(1,408,744,122.98)	(1,406,608,671.92)	(1,406,328,060.85)	(1,432,724,712.55)
	2160 Total			**(1,504,288,277.92)**	**(1,394,831,221.55)**	**(1,406,918,019.73)**	**(1,408,744,122.98)**	**(1,406,608,671.92)**	**(1,406,328,060.85)**	**(1,432,724,712.55)**
4380	**Div Declrd - Common Stock**	4380001	Div Declrd - Common Stk - Asso	120,000,000.00		-	20,000,000.00	20,000,000.00	20,000,000.00	40,000,000.00
	4380 Total			**120,000,000.00**	**-**	**-**	**20,000,000.00**	**20,000,000.00**	**20,000,000.00**	**40,000,000.00**
4390	**Adj to Retained Earnings**	4390000	Adj to Retained Earnings			-	-	399,934.61	399,934.61	399,934.61

Southerwestern Electric Power Company
Trial Balance - Balance Sheet
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

FERC	FERC Title	Account	Description	Balance 12/31/16	Balance 12/31/17	Balance 1/31/18	Balance 2/28/18	Balance 3/31/18 (Actual)	Balance 4/30/18 (Actual)	Balance 5/31/18 (Actual)
	4390 Total			**-**	**-**	**-**	**-**	**399,934.61**	**399,934.61**	**399,934.61**
2161	**Unapprp Undistrbutd Sub Erngs**	2161001	Unap Undist Consol Sub Erng	(11,379,399.24)	(11,406,570.86)	(11,406,570.86)	(11,406,570.86)	(11,406,570.86)	(11,406,570.86)	(11,406,570.86)
		2161002	Unap Undist Nonconsol Sub Erng	(16,222,452.36)	(20,337,917.51)	(20,337,917.51)	(20,337,917.51)	(20,337,917.51)	(20,337,917.51)	(20,337,917.51)
	2161 Total			**(27,601,851.60)**	**(31,744,488.37)**	**(31,744,488.37)**	**(31,744,488.37)**	**(31,744,488.37)**	**(31,744,488.37)**	**(31,744,488.37)**
2190	**OCI - FAS 133**	2190007	OCI-Min Pen Liab FAS 158-OPEB	2,095,020.29	(1,856,839.24)	(1,856,839.24)	(1,856,839.24)	(1,913,282.23)	(1,913,282.23)	(1,913,282.23)
		2190015	Accum OCI-Hdg-CF-Int Rate	7,310,974.91	5,872,750.31	5,752,898.26	6,846,317.73	6,700,651.30	6,554,984.95	6,409,318.60
	2190 Total			**9,405,995.20**	**4,015,911.07**	**3,896,059.02**	**4,989,478.49**	**4,787,369.07**	**4,641,702.72**	**4,496,036.37**
2240	**Other Long Term Debt**	2240002	Installment Purchase Contracts	(135,200,000.00)	(135,200,000.00)	(81,700,000.00)	-	-	-	-
		2240005	Other Long Term Debt - Other	(0.00)	(115,000,000.00)	(115,000,000.00)	(115,000,000.00)	(115,000,000.00)	(115,000,000.00)	(115,000,000.00)
		2240006	Senior Unsecured Notes	(2,125,000,000.00)	(2,125,000,000.00)	(2,175,000,000.00)	(1,875,000,000.00)	(1,875,000,000.00)	(1,875,000,000.00)	(1,875,000,000.00)
		2240502	Instl Purchase Contracts-Curr			(53,500,000.00)	(135,200,000.00)	(53,500,000.00)	(53,500,000.00)	(53,500,000.00)
		2240505	Oth LTD - Other - Current	(100,000,000.00)						
		2240506	Senior Unsecured Notes-Current	(250,000,000.00)		(400,000,000.00)	(700,000,000.00)	(400,000,000.00)	(400,000,000.00)	(400,000,000.00)
	2240 Total			**(2,610,200,000.00)**	**(2,375,200,000.00)**	**(2,825,200,000.00)**	**(2,825,200,000.00)**	**(2,443,500,000.00)**	**(2,443,500,000.00)**	**(2,443,500,000.00)**
2260	**Unam Disc LTD - Debit**	2260006	Unam Disc LTD-Dr-Sr Unsec Note	4,694,753.41	4,262,652.96	5,182,482.09	5,143,811.38	5,114,018.55	5,084,225.73	5,054,432.91
	2260 Total			**4,694,753.41**	**4,262,652.96**	**5,182,482.09**	**5,143,811.38**	**5,114,018.55**	**5,084,225.73**	**5,054,432.91**
2270	**Obligatns Undr Cap Lse-Noncurr**	2270001	Obligatns Undr Cap Lse-Noncurr	(23,963,316.16)	(22,654,828.66)	(22,456,102.31)	(22,294,486.42)	(22,235,942.22)	(23,056,526.27)	(23,270,747.97)
		2270003	Accrued Noncur Lease Oblig	(80,450.20)	(53,543.94)	(99,588.87)	(113,442.62)	(1,236,765.81)	(403,672.57)	(131,564.61)
	2270 Total			**(24,043,766.36)**	**(22,708,372.60)**	**(22,555,691.18)**	**(22,407,929.04)**	**(23,472,708.03)**	**(23,460,198.84)**	**(23,402,312.58)**
2282	**Accm Prov for Injuries&Damages**	2282003	Accm Prv I/D - Worker's Com	(54,000.47)	(108,919.11)	(42,656.47)	(41,748.71)	(53,349.36)	(55,654.58)	(117,826.12)
	2282 Total			**(54,000.47)**	**(108,919.11)**	**(42,656.47)**	**(41,748.71)**	**(53,349.36)**	**(55,654.58)**	**(117,826.12)**
2283	**Accm Prv for Pensions&Benefits**	2283000	Accm Prv for Pensions&Benefits	(1,072,287.00)	(1,070,041.39)	(1,079,152.51)	(1,088,263.63)	(1,091,625.74)	(1,098,820.53)	(1,106,015.32)
		2283001	Deferred Compensation Plan	(1,695,071.49)	(1,695,071.49)	(1,695,071.49)	(1,695,071.49)	(1,695,071.49)	(1,695,071.49)	(1,695,071.49)
		2283002	Supplemental Savings Plan	(1,084,596.53)	(1,158,618.59)	(1,147,900.76)	(1,147,900.76)	(1,158,845.63)	(1,158,845.63)	(1,158,845.63)
		2283005	SFAS 112 Postemployment Benef	(4,972,743.72)	(3,587,589.39)	(3,587,589.39)	(3,587,589.39)	(4,042,857.19)	(4,042,857.19)	(4,042,857.19)
		2283006	SFAS 87 - Pensions	0.00		(711,385.00)	(1,422,770.00)	(2,028,939.50)	(2,705,252.66)	(3,381,565.82)
		2283007	Perf Share Incentive Plan	(4,197,905.46)	(1,245,855.15)	(3,393,573.20)	(1,225,135.52)	(0.00)	0.00	0.00
		2283013	Incentive Comp Deferral Plan	(121,030.72)	(102,943.41)	(102,943.41)	(130,533.30)	(130,594.85)	(130,594.85)	(130,594.85)
		2283015	FAS 158 SERP Payable Long Term	(508,912.00)	(979,459.00)	(979,459.00)	(979,459.00)	(965,066.25)	(965,066.25)	(965,066.25)
		2283016	FAS 158 Qual Payable Long Term	(7,632,275.71)	(660,392.71)	(660,392.71)	(660,392.71)	592,291.04	592,291.04	592,291.04
	2283 Total			**(21,284,822.62)**	**(10,499,971.12)**	**(13,357,467.46)**	**(11,937,115.79)**	**(10,520,709.61)**	**(11,204,217.56)**	**(11,887,725.51)**
2290	**Acc Prov for Rate Refunds**	2290002	Acc Prv Rate Refnds-Nonassoc		(9,676,544.40)	(11,650,976.93)	(11,219,167.49)	(5,124,362.92)	(6,062,552.54)	(6,888,967.08)
		2290006	Acc Prv for Potential Refund	(1,211,439.92)	(2,624,999.89)	(4,576,180.80)	(2,624,999.89)	-	-	-
		2290018	Acc Prov Refunds - Tax Reform			-	(8,825,133.50)	(11,073,930.77)	(13,928,889.70)	(17,521,985.35)
		2290019	Acc Prov Refund-Excess Protect			-	-	(3,507,507.82)	(4,676,677.09)	(5,845,846.36)
	2290 Total			**(1,211,439.92)**	**(12,301,544.29)**	**(16,227,157.73)**	**(22,669,300.88)**	**(19,705,801.51)**	**(24,668,119.33)**	**(30,256,798.79)**
2300	**Asset Retirement Obligations**	2300001	Asset Retirement Obligations	(74,046,205.74)	(83,838,274.83)	(83,768,134.43)	(83,666,783.32)	(83,522,049.92)	(82,890,494.11)	(82,435,940.95)
		2300002	ARO - Current	(9,407,900.50)	(8,919,951.00)	(8,919,951.00)	(8,919,951.00)	(8,919,951.00)	(8,919,951.00)	(8,919,951.00)
	2300 Total			**(83,454,106.24)**	**(92,758,225.83)**	**(92,688,085.43)**	**(92,586,734.32)**	**(92,442,000.92)**	**(91,810,445.11)**	**(91,355,891.95)**
2320	**Accounts Payable**	2320001	Accounts Payable - Regular	(29,177,974.62)	(48,641,920.36)	(45,928,448.02)	(43,193,337.22)	(31,294,902.53)	(33,538,340.42)	(27,121,528.92)
		2320002	Unvouchered Invoices	(30,163,943.10)	(28,913,936.62)	(23,382,094.13)	(29,896,479.49)	(30,073,727.15)	(32,440,280.69)	(26,356,119.21)
		2320003	Retention	(6,485,989.48)	(4,350,562.32)	(4,280,140.15)	(5,129,158.55)	(5,788,127.53)	(6,718,893.00)	(7,799,214.33)
		2320008	Miscellaneous Liabilities	(71,678.83)						
		2320011	Uninvoiced Fuel	(17,937,239.17)	(21,496,342.12)	(29,633,724.31)	(23,091,292.41)	(17,168,675.84)	(11,077,127.08)	(18,292,018.70)
		2320052	Accounts Payable - Purch Power	(7,868,264.92)	(11,890,047.51)	(12,787,234.12)	(10,534,204.64)	(9,042,403.43)	(9,473,562.20)	(8,876,727.81)
		2320054	Emission Allowance Trading	(176.71)		700.00	700.00	-	700.00	700.00
		2320062	Broker Fees Payable	(3,379.47)	(2,498.02)	(3,228.91)	(3,229.96)	(3,229.96)	(2,889.98)	(3,514.98)
		2320066	A/P - OPEN ACCESS TRANS EXP	(8,934,839.92)	(11,284,422.48)	(10,843,454.44)	(11,661,950.42)	(11,623,671.02)	(11,638,579.29)	(11,691,026.00)
		2320075	Unvouch - Dolet Hills - Cleco	(1,293,246.29)	(1,326,250.43)	(1,400,730.92)	(3,625,870.71)	15,531.79	(2,004,412.06)	(2,318,659.57)
		2320076	Corporate Credit Card Liab	(223,171.35)	(153,534.58)	(268,453.87)	(266,965.52)	(358,608.51)	(272,697.67)	(245,576.32)
		2320077	INDUS Unvouchered Liabilities	(3,381,788.65)	(9,331,714.99)	(6,410,622.17)	(6,139,951.77)	(2,481,691.05)	(2,423,179.97)	(3,195,631.11)
		2320089	Mattison-Centerpoint Payable	(10,221,055.40)	(16,884,859.08)	(1,319,308.02)	(2,767,824.96)	(4,223,699.78)	(5,505,830.96)	(6,733,479.26)
		2320090	MISO AP Accrual		(562,435.75)	(890,298.10)	(627,378.12)	(562,435.75)	(232,364.69)	(290,025.96)

Southerwestern Electric Power Company
Trial Balance - Balance Sheet
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

FERC	FERC Title	Account	Description	Balance 12/31/16	Balance 12/31/17	Balance 1/31/18	Balance 2/28/18	Balance 3/31/18	Balance 4/30/18	Balance 5/31/18
							Actual			
	2320 Total			**(115,762,747.92)**	**(154,838,524.27)**	**(137,147,037.16)**	**(136,936,943.77)**	**(112,605,640.76)**	**(115,327,458.01)**	**(112,922,822.18)**
2330	**Corp Borrow Program (NP-Assoc)**	2330000	Corp Borrow Program (NP-Assoc)	-	(118,680,358.41)	-	-	(148,611,785.14)	(184,673,602.14)	(182,836,469.32)
	2330 Total			**-**	**(118,680,358.41)**	**-**	**-**	**(148,611,785.14)**	**(184,673,602.14)**	**(182,836,469.32)**
2340	**Accounts Pay to Assoc Co**	2340001	A/P Assoc Co - InterUnit G/L	(27,379,528.11)	(33,403,525.78)	(24,530,946.46)	(20,681,628.21)	(32,599,460.95)	(18,002,640.59)	(25,183,503.11)
		2340025	A/P Assoc Co - CM Bills	(11,273.37)	(6,835.71)	(154.01)	(56,950.13)	(170,230.74)	(260,048.85)	(19,020.45)
		2340027	A/P Assoc Co - Intercompany	(368,235.41)	(701,828.17)	(1,104,828.18)	(24,001.37)	(740,909.70)	(614,300.26)	(311.19)
		2340029	A/P Assoc Co - AEPSC Bills	(20,810,183.48)	(20,552,805.17)	(12,680,600.89)	(11,157,230.67)	(11,807,681.61)	(12,567,531.53)	(12,180,844.95)
		2340030	A/P Assoc Co - InterUnit A/P	(9,435.84)	(89,073.97)	(194,647.32)	(114,938.98)	(165.52)	(88,443.05)	(3,697,889.86)
		2340032	A/P Assoc Co - Multi Pmts	(60,970.21)	(2,396.51)	(2,618.32)	(20,388.10)	(886.89)	(18.66)	(1,672.59)
		2340033	A/P Assoc Co - Factored A/R	(46,204,444.67)	(44,153,373.43)	(42,973,282.31)	(40,119,650.57)	(39,993,999.82)	(47,792,681.90)	(53,222,234.30)
		2340035	Fleet - M4 - A/P	(3,795.22)	(4,992.36)	(10,250.93)	(12,204.83)	(15,032.97)	(24,507.32)	(10,480.34)
		2340041	A/P Assc Co - Non-InterUnit GL	(15,568,962.00)	(13,897,954.71)	(12,494,835.88)	(11,191,739.74)	(13,025,694.07)	(5,669,082.27)	(16,551,718.79)
	2340 Total			**(110,416,828.31)**	**(112,812,785.81)**	**(93,992,164.30)**	**(83,378,732.60)**	**(98,354,062.27)**	**(85,019,254.43)**	**(110,867,675.58)**
2350	**Customer Deposits**	2350001	Customer Deposits-Active	(62,117,036.10)	(62,112,566.67)	(62,283,421.05)	(62,490,555.96)	(62,867,579.56)	(63,163,610.99)	(63,804,370.07)
		2350003	Deposits - Trading Activity			-	(537,244.39)	(12,806.97)	0.00	(44,864.72)
	2350 Total			**(62,117,036.10)**	**(62,112,566.67)**	**(62,283,421.05)**	**(63,027,800.35)**	**(62,880,386.53)**	**(63,163,610.99)**	**(63,849,234.79)**
2360	**Taxes Accrued**	2360001	Federal Income Tax	51,494,692.98	2,678,011.03	134,491.90	(451,507.65)	478,165.91	9,901,045.76	6,183,324.79
		236000215	State Income Taxes	12,320.00	12,320.00	12,320.00	12,320.00	12,320.00	12,320.00	12,320.00
		236000216	State Income Taxes	(1,308,013.92)						
		236000217	State Income Taxes		(4,548.84)	(4,548.84)	(4,548.84)	(4,548.84)	(4,548.84)	845,451.16
		236000218	State Income Taxes			(739,929.24)	(860,871.61)	(442,381.09)	(113,382.62)	(1,522,844.48)
		2360004	FICA	(352,500.39)	(374,732.90)	(478,916.68)	(491,632.86)	(200,363.72)	(267,597.04)	(345,048.33)
		2360005	Federal Unemployment Tax	(28,371.55)	(29,341.21)	(62,347.94)	(62,658.35)	(63,477.05)	(450.07)	(777.46)
		2360006	State Unemployment Tax	(40,532.45)	(36,579.48)	(66,185.14)	(66,038.50)	(67,136.89)	(544.79)	(856.34)
		236000700	State Sales and Use Taxes		(311,500.00)	(311,500.00)	(325,500.00)	-	-	-
		236000716	State Sales and Use Taxes	(1,431,168.80)		-	-	(0.01)	-	-
		236000717	State Sales and Use Taxes		(2,132,071.22)	(199,755.14)	(375,301.82)	14,793.74	14,793.74	179,765.99
		236000718	State Sales and Use Taxes			(2,014,689.43)	(1,479,908.53)	(1,660,291.12)	(1,545,222.32)	(877,675.65)
		236000816	Real Personal Property Taxes	(29,764,873.19)						
		236000817	Real Personal Property Taxes		(30,689,410.25)	(16,182,061.33)	(15,644,432.26)	(15,120,873.37)	(11,290,892.24)	(11,290,892.24)
		236000818	Real Personal Property Taxes			(66,123,082.00)	(66,123,082.00)	(66,123,082.00)	(66,123,082.00)	(66,123,082.00)
		236001205	State Franchise Taxes		-	-	-	-	-	-
		236001216	State Franchise Taxes	(15,100.00)						
		236001217	State Franchise Taxes		363,855.99	363,855.99	363,855.99	363,855.99	363,855.99	363,855.99
		236001218	State Franchise Taxes			(1,404,100.00)	(1,404,100.00)	(1,404,100.00)	(1,167,000.00)	2,672,000.00
		236002016	State Public Service Com Tax	(811,326.00)						
		236002017	State Public Service Com Tax		(808,326.00)	(928,047.00)	(1,047,768.00)	(1,077,489.00)	(1,197,210.00)	(1,316,931.00)
		236002018	State Public Service Com Tax			(42,000.00)	(84,000.00)	(126,000.00)	(166,000.00)	(206,000.00)
		236002206	State License/Registration Tax		-	-	-	-	-	-
		236002208	State License/Registration Tax		-	-	-	-	-	-
		236002516	Local Franchise Tax	(3,647,833.23)						
		236002517	Local Franchise Tax		(3,719,365.87)	-	-	-	-	-
		236002518	Local Franchise Tax			(1,635,953.00)	(2,811,803.06)	(3,844,277.17)	(1,194,648.09)	(2,342,390.39)
		236003316	Pers Prop Tax-Cap Leases	(107,446.14)						
		236003317	Pers Prop Tax-Cap Leases		(97,836.94)	9,468.86	-	-	-	-
		236003318	Pers Prop Tax-Cap Leases			(173,000.00)	(173,000.00)	(173,000.00)	(173,000.00)	(173,000.00)
		2360037	FICA - Incentive accrual	(1,166,519.95)	(624,304.31)	(688,604.10)	(758,347.04)	(190,492.98)	(254,793.06)	(319,183.20)
		2360501	Fed Inc Tax-Short Term FIN48			-	-	247,135.74	247,135.74	247,135.74
		2360502	State Inc Tax-Short Term FIN48	(34,561.00)	(53,646.00)	(53,646.00)	(53,646.00)	(53,646.00)	(53,646.00)	(53,646.00)
		2360601	Fed Inc Tax-Long Term FIN48	432,721.00	432,721.00	432,720.99	432,720.99	-	-	-
		2360602	State Inc Tax-Long Term FIN48	2,763,649.00	761,734.00	761,734.00	761,734.00	761,734.00	761,734.00	761,734.00
		2360701	SEC Accum Defd FIT-Util FIN 48			0.01	0.01	0.01	0.01	0.01
		2360702	SEC Accum Defd SIT - FIN 48	98,438.00	99,070.00	99,070.00	99,070.00	99,070.00	99,070.00	99,070.00
		2360801	Federal Income Tax - IRS Audit	(185,585.25)	(185,585.25)	(185,585.25)	(185,585.25)	-	-	-
		2360901	Accum Defd FIT- IRS Audit	(1,356,241.75)	(1,356,241.75)	(1,356,241.75)	(1,356,241.75)	(1,356,241.75)	(1,356,241.75)	(1,356,241.75)
	2360 Total			**14,551,747.36**	**(36,075,778.00)**	**(90,836,531.09)**	**(92,090,272.53)**	**(89,930,325.60)**	**(73,508,303.58)**	**(74,563,911.16)**
2370	**Interest Accrued**	2370002	Interest Accrued-Inst Pur Con	(1,722,037.22)	(1,722,037.22)	(1,702,383.05)	(2,110,728.88)	(213,999.99)	(285,333.33)	(356,666.66)
		2370005	Interest Accrd-Other LT Debt	(586,402.49)	(56,055.68)	(345,676.28)	(607,269.08)	(62,128.82)	(372,772.58)	(74,933.27)

Southerwestern Electric Power Company
Trial Balance - Balance Sheet
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

FERC	FERC Title	Account	Description	Balance 12/31/16	Balance 12/31/17	Balance 1/31/18 (Actual)	Balance 2/28/18 (Actual)	Balance 3/31/18 (Actual)	Balance 4/30/18 (Actual)	Balance 5/31/18 (Actual)
		2370006	Interest Accrd-Sen Unsec Notes	(40,939,378.01)	(34,480,350.02)	(30,470,766.66)	(35,490,558.29)	(24,260,349.92)	(19,392,641.58)	(27,824,933.21)
		2370007	Interest Accrd-Customer Depsts	(1,484,124.16)	(1,532,468.51)	(117,266.44)	(253,105.30)	(402,761.96)	(546,265.80)	(692,755.59)
		2370018	Accrued Margin Interest		0.00	0.00	0.00	0.00	0.00	0.00
		2370025	Interest Over Recover - AR	(68,489.23)						
		2370348	Acrd Int. - SIT Reserve - LT		(2,474.00)	(2,474.00)	(2,474.00)	(3,497.00)	(3,497.00)	(3,497.00)
		2370448	Acrd Int. - SIT Reserve - ST	(11,568.00)	(15,990.00)	(15,990.00)	(15,990.00)	(17,154.00)	(17,154.00)	(17,154.00)
	2370 Total			**(44,811,999.12)**	**(37,809,375.43)**	**(32,654,556.43)**	**(38,480,125.55)**	**(24,959,891.69)**	**(20,617,664.29)**	**(28,969,939.73)**
2380	**Dividends Declared**	2380003	Div Decl - Common Stock-Affil		-	-	-	-	-	-
	2380 Total			**-**	**-**	**-**	**-**	**-**	**-**	**-**
2410	**Tax Collections Payable**	2410002	State Income Tax Withheld	(169,476.69)	(177,245.67)	(175,282.03)	(178,833.24)	(424,461.24)	(203,763.76)	(255,847.20)
		2410003	Local Income Tax Withheld		(346.17)	(161.14)	(161.14)	(161.14)	-	-
		2410004	State Sales Tax Collected	(2,191,036.75)	(2,342,264.37)	(3,930,406.80)	(2,884,436.24)	(2,734,851.33)	(3,239,053.36)	(2,669,647.06)
		2410005	FICA Tax Withheld	0.00		-	-	-	-	(11,025.00)
		2410008	Franchise Fee Collected	(3,123,323.54)	(3,316,159.15)	(1,444,955.06)	(2,546,621.54)	(3,513,600.51)	(1,090,058.12)	(2,231,032.59)
	2410 Total			**(5,483,836.98)**	**(5,836,015.36)**	**(5,550,805.03)**	**(5,610,052.16)**	**(6,673,074.22)**	**(4,532,875.24)**	**(5,167,551.85)**
2420	**Misc Current & Accrued Liab**	2420000	Misc Current & Accrued Liab	(18,069.00)	(18,069.00)	(18,069.00)	(18,069.00)	(18,069.00)	(18,069.00)	(18,069.00)
		2420002	P/R Ded - Medical Insurance	(335,726.59)	(358,843.08)	(356,356.44)	(354,974.02)	(358,507.92)	(357,337.66)	(357,296.93)
		2420003	P/R Ded - Dental Insurance	(41,753.00)	(42,850.44)	(43,276.85)	(43,239.40)	(43,356.63)	(43,216.15)	(43,336.83)
		2420007	P/R Ded - Savings Plan			(59.36)	-	-	-	-
		2420010	P/R Ded - Dependent Life Ins							
		2420013	P/R Ded - LTD Ins Premiums	(4,758.79)	(4,741.26)	(5,257.55)	(5,256.96)	(5,252.82)	(5,264.74)	(5,273.47)
		2420016	P/R Ded-Crt Ordr/Grnshmt/Tx Lv							
		2420017	P/R Ded - AD&D and OAD&D Ins							
		2420018	P/R Ded-Reg&Spec Life Ins Prem							
		2420020	Vacation Pay - This Year			(11,586,505.24)	(11,230,993.51)	(10,670,078.11)	(10,151,882.48)	(9,297,814.69)
		2420021	Vacation Pay - Next Year	(11,956,337.03)	(12,207,437.79)	(1,661,003.83)	(2,106,113.79)	(2,876,444.06)	(3,625,490.21)	(4,425,042.73)
		2420027	FAS 112 CURRENT LIAB	(1,264,564.00)	(1,257,474.61)	(1,257,474.61)	(1,257,474.61)	(1,510,148.81)	(1,510,148.81)	(1,510,148.81)
		2420028	ESP - Employer Contrib Accrued			(50.46)	-	-	-	-
		2420046	FAS 158 SERP Payable - Current	(116,338.00)	(150,521.00)	(150,521.00)	(150,521.00)	(150,521.00)	(150,521.00)	(150,521.00)
		2420051	Non-Productive Payroll	(671,127.31)	(539,493.45)	(408,024.46)	(259,540.40)	(98,070.74)	(248,590.47)	(105,779.05)
		2420053	Perf Share Incentive Plan	(2,086,834.00)	(2,138,758.00)	-	-	(1,218,915.49)	(1,252,915.52)	(1,211,075.61)
		2420059	MINE CLOSING COSTS - FERC	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
		2420071	P/R Ded - Vision Plan	(16,667.07)	(16,862.77)	(17,178.06)	(17,152.53)	(17,213.86)	(17,192.53)	(17,202.94)
		2420072	P/R - Payroll Adjustment	(4,302.19)		(145.84)	(145.84)	(145.84)	(145.84)	(145.84)
		2420076	P/R Savings Plan - Incentive	(632,244.05)	(335,714.67)	(370,274.36)	(407,722.51)	(102,265.96)	(136,426.59)	(170,636.64)
		2420081	Environmntl Remediation Accrua	(25,974.22)	(26,136.75)	(26,136.75)	(26,136.75)	(26,136.75)	(26,136.75)	(26,136.75)
		2420083	Active Med and Dental IBNR		(274,693.10)	-	-	-	-	-
		2420504	Accrued Lease Expense	(466,300.40)	(151,128.54)	(336,547.64)	(390,176.04)	(571,327.62)	(520,747.02)	(742,163.73)
		2420511	Control Cash Disburse Account	(4,544,647.27)	(4,868,929.20)	(20,691,898.62)	(4,143,338.76)	(693,422.64)	(2,132,219.98)	(3,746,239.99)
		2420512	Unclaimed Funds	(56,037.35)	(28,821.24)	(28,821.24)	(28,821.24)	(29,621.40)	(27,589.26)	(25,693.61)
		2420514	Revenue Refunds Accrued	(1,531,466.04)		-	-	(1,000,000.00)	(1,125,000.00)	(1,250,000.00)
		2420519	Provision for Unclaimed Funds	(2,750,000.00)						
		2420532	Adm Liab-Cur-S/Ins-W/C	(133,520.21)	(89,758.96)	(136,709.89)	(137,053.57)	(122,364.36)	(139,980.10)	(132,297.54)
		242053818	Federal Admin Fee			-	-	-	-	-
		2420558	Admitted Liab NC-Self/Ins-W/C	(181,805.40)	(270,420.70)	(203,163.43)	(192,089.27)	(239,116.91)	(222,489.10)	(655,602.43)
		242059216	Sales Use Tax - Leased Equip	(71.14)						
		242059217	Sales Use Tax - Leased Equip		(195.53)	-	-	-	-	-
		242059218	Sales Use Tax - Leased Equip			(3,576.99)	(13,569.01)	(2,545.51)	(195.53)	(2,766.16)
		2420618	Accrued Payroll	(4,389,723.74)	(4,677,241.15)	(6,056,079.45)	(5,926,039.91)	(2,279,381.28)	(2,703,440.54)	(4,136,575.65)
		2420623	Distr, Cust Ops & Reg Svcs ICP	(7,873,061.00)	(4,026,476.00)	(4,440,055.82)	(4,894,714.98)	(1,214,613.94)	(1,618,908.54)	(2,024,354.82)
		2420624	Corp & Shrd Srv Incentive Plan	(733,038.00)	(515,265.00)	(565,579.53)	(629,824.53)	(150,156.43)	(199,860.81)	(250,268.81)
		2420635	Generation Incentive Plan	(6,333,519.00)	(3,326,699.00)	(3,682,808.52)	(4,035,653.52)	(1,061,131.57)	(1,414,519.77)	(1,768,555.77)
		2420643	Accrued Audit Fees	(375.50)	(7,738.12)	(93,139.22)	(178,540.32)	(275,762.35)	(365,103.77)	(206,211.28)
		2420644	Reclamation Liability - Affil	(73,052,128.00)	(76,423,070.00)	(76,716,948.00)	(77,010,826.00)	(77,304,704.00)	(77,598,582.00)	(77,892,460.00)
		2420649	Reclamation Liability - Curr	(2,536.84)	(2,533.76)	(1,307.16)	(1,630.81)	(2,459.51)	(1,708.00)	(1,862.59)
		2420660	AEP Transmission ICP	(1,243,207.00)	(756,476.00)	(823,209.82)	(914,189.82)	(198,562.79)	(264,750.79)	(330,938.79)
		2420662	Accrued Railcar Lease Exp - ST	(12,687.29)	(12,687.29)	(12,687.29)	(12,687.29)	(12,687.29)	(12,687.29)	(12,687.29)
		2420663	Accrued railcar lease exp - LT	(121,356.66)	(103,445.46)	(101,973.67)	(100,501.88)	(99,030.09)	(97,558.30)	(96,086.51)
		2420665	Dollar Energy Assistance Pgm	(1,923.87)	(1,710.54)	(1,814.55)	(1,334.80)	(1,395.03)	(1,558.83)	(1,338.96)
		2420700	Quality of Service	(49,114.00)		-	-	-	-	-

Southerwestern Electric Power Company
Trial Balance - Balance Sheet
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

FERC	FERC Title	Account	Description	Balance 12/31/16	Balance 12/31/17	Actual Balance 1/31/18	Balance 2/28/18	Balance 3/31/18	Balance 4/30/18	Balance 5/31/18
	2420 Total			**(120,651,213.95)**	**(112,634,192.42)**	**(129,796,654.66)**	**(114,488,332.08)**	**(102,353,409.72)**	**(105,990,237.38)**	**(110,614,584.22)**
2430	**Oblig Under Cap Leases - Curr**	2430001	Oblig Under Cap Leases - Curr	(4,592,948.26)	(4,284,287.29)	(4,229,921.98)	(4,264,687.43)	(4,206,362.75)	(4,245,971.79)	(4,280,394.75)
		2430003	Accrued Cur Lease Oblig	(20,112.51)	(9,319.79)	(24,826.92)	(28,360.68)	(142,508.30)	(62,885.94)	(29,365.13)
	2430 Total			**(4,613,060.77)**	**(4,293,607.08)**	**(4,254,748.90)**	**(4,293,048.11)**	**(4,348,871.05)**	**(4,308,857.73)**	**(4,309,759.88)**
2440	**Curr. Unreal Losses - NonAffil**	2440001	Curr. Unreal Losses - NonAffil	(261,843.67)	(183,287.65)	-	(228,057.65)	(60,072.40)	(1,152,734.12)	(7,700.02)
		2440002	LT Unreal Losses - Non Affil		(4,185.75)	(254,502.99)	(929,436.02)	(547,737.26)	(1,624,172.61)	(2,065,806.62)
	2440 Total			**(261,843.67)**	**(187,473.40)**	**(254,502.99)**	**(1,157,493.67)**	**(607,809.66)**	**(2,776,906.73)**	**(2,073,506.64)**
2530	**Other Deferred Credits**	2530000	Other Deferred Credits	(214,176.70)	(196,339.98)	(193,096.94)	(184,742.92)	(6,582,133.90)	(6,455,512.38)	(6,328,890.86)
		2530022	Customer Advance Receipts	(4,453,534.58)	(4,185,331.86)	(3,700,711.76)	(4,026,277.33)	(4,846,641.25)	(5,571,988.47)	(5,533,315.62)
		2530050	Deferred Rev -Pole Attachments	(1,121,419.97)	(1,051,208.88)	(902,035.32)	(727,054.60)	(550,081.25)	(373,107.90)	(196,134.55)
		2530067	IPP - System Upgrade Credits	(6,006,382.36)	(6,804,195.38)	(6,825,055.12)	(6,845,914.86)	(6,846,112.91)	(6,872,719.32)	(6,895,440.33)
		2530101	MACSS Unidentified EDI Cash	(5,754.30)	(800.16)	-	(17,767.71)	(7,071.47)	(7,475.74)	(6,777.39)
		2530104	Railroad Cars Subleased-Rev	-		-	-	-	-	(44,531.82)
		2530112	Other Deferred Credits-Curr	(760,094.84)	(594,627.83)	(159,853.90)	(180,936.26)	(165,634.97)	(321,375.70)	(171,689.90)
		2530120	Environ Remediation LT	(147,162.02)	(143,956.85)	(143,956.85)	(143,956.85)	(143,956.85)	(143,956.85)	(143,956.85)
		2530124	Contr In Aid of Constr Advance	(312,391.85)	(452,585.46)	(455,670.53)	(563,085.64)	(434,233.16)	(353,639.01)	(397,734.11)
		2530139	IPP - Aff. Sys Upgrade Credits	-	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
		2530181	Oxbow Buy In	(2,974,015.03)	(2,864,333.75)	(2,855,593.64)	(2,847,042.35)	(2,838,498.11)	(2,832,034.72)	(2,825,571.33)
		2530185	O\U Accounting of ExpensesT			-	-	(174,954.49)	-	-
		2530188	Long Term Assoc AP			-	-	-	-	-
		2530190	QUAL OF SVC PENALTIES - LT			-	-	(100,987.50)	(100,987.50)	(100,987.50)
	2530 Total			**(15,994,931.65)**	**(16,293,380.15)**	**(15,235,974.06)**	**(15,536,778.52)**	**(22,690,305.86)**	**(23,032,797.59)**	**(22,645,030.26)**
2540	**Other Regulatory Liabilities**	2540047	Unreal Gain on Fwd Commitments	(1,040,606.21)	(2,842,711.86)	(1,601,732.22)	(280,316.87)	-	(301,484.00)	(331,672.00)
		2540050	Def Rev Selling Price Variance	-		(1,147,001.41)	(650,783.53)	-	-	-
		2540052	EXCESS EARNINGS	(2,687,476.00)	(2,615,476.00)	(2,609,476.00)	(2,603,476.00)	(2,597,476.00)	(2,591,476.00)	(2,585,476.00)
		2540058	Dolet Hills Mining Buy-Out	(293,718.26)	(272,905.57)	(272,905.57)	(272,905.57)	(272,905.57)	(272,905.57)	(272,905.57)
		2540090	Over Recovered Fuel Cost - TX	(3,702,497.87)	(7,494,126.26)	(3,500,807.03)	(3,854,959.31)	(6,404,469.89)	(7,247,124.87)	(4,740,223.41)
		2540094	Over Recovered Fuel Cost - LA		(1,169,311.86)	(2,762.00)	-	-	(1,206,824.19)	(3,213.00)
		2540118	Energy Efficiency O/U Recovery			(222,979.11)	(246,024.70)	(65,682.69)	(149,441.58)	(247,231.01)
		2540137	Over Recovered EAC - LA			-	-	-	(33,879.04)	-
		2540139	Refundable Construction Int-LA	(16,213,372.10)						
		2540174	JLStall GR Rider Over Recovery	(1,234,364.84)	(1,276,748.15)	(1,458,014.29)	(1,562,348.90)	(1,530,914.93)	(1,499,593.40)	(1,735,408.71)
		2540184	Texas Vegetation Management	(384,339.54)	(3,088,370.49)	(3,694,273.75)	(4,214,617.21)	(4,590,564.99)	(4,623,426.00)	(3,440,493.51)
		2540191	LA SQIP Veg Mgmt O/U Recovery			(614,722.21)	(1,234,764.68)	(1,903,732.57)	(2,570,399.24)	(3,105,032.67)
	2540 Total			**(25,556,374.82)**	**(18,759,650.19)**	**(15,124,673.59)**	**(14,920,196.77)**	**(17,365,746.64)**	**(20,496,553.89)**	**(16,461,655.88)**
2543	**SFAS 109 Flow Thru Defd FIT**	2543001	SFAS109 Flow Thru Def FIT Liab	(3,915,276.08)	(1,570,016.61)	(1,538,511.84)	(1,507,007.05)	(1,475,502.26)	(1,443,997.49)	(1,412,492.69)
	2543 Total			**(3,915,276.08)**	**(1,570,016.61)**	**(1,538,511.84)**	**(1,507,007.05)**	**(1,475,502.26)**	**(1,443,997.49)**	**(1,412,492.69)**
2544	**SFAS 109 Exces Deferred FIT**	2544001	SFAS 109 Exces Deferred FIT	(199,161.21)	(714,506,057.66)	(714,455,894.21)	(714,402,729.64)	(711,164,290.42)	(710,049,367.63)	(708,934,444.85)
		2544009	OCI - Excess DFIT		1,264,900.10	1,264,900.10	-	-	-	-
	2544 Total			**(199,161.21)**	**(713,241,157.56)**	**(713,190,994.11)**	**(714,402,729.64)**	**(711,164,290.42)**	**(710,049,367.63)**	**(708,934,444.85)**
2550	**Accum Def Invest Tax Credit**	2550001	Accum Deferred ITC - Federal	(7,271,227.00)	(5,906,253.00)	(5,787,735.00)	(5,669,217.00)	(5,550,699.00)	(5,432,181.00)	(5,313,663.00)
	2550 Total			**(7,271,227.00)**	**(5,906,253.00)**	**(5,787,735.00)**	**(5,669,217.00)**	**(5,550,699.00)**	**(5,432,181.00)**	**(5,313,663.00)**
2570	**Unamt Gain on Reacquired Debt**	2570001	Unamort Gn Reacq Debt - FMB	(31,122.10)	(20,010.58)	(19,084.62)	(18,158.66)	(17,232.70)	(16,306.74)	(15,380.79)
	2570 Total			**(31,122.10)**	**(20,010.58)**	**(19,084.62)**	**(18,158.66)**	**(17,232.70)**	**(16,306.74)**	**(15,380.79)**
2811	**Acc Def Inc Tax-Acc Amort Prop**	2811001	Acc Dfd FIT - Accel Amort Prop	(67,317,600.00)	(67,118,483.25)	(40,384,069.95)	(40,497,049.95)	(67,492,731.95)	(67,579,041.95)	(67,665,351.95)
	2811 Total			**(67,317,600.00)**	**(67,118,483.25)**	**(40,384,069.95)**	**(40,497,049.95)**	**(67,492,731.95)**	**(67,579,041.95)**	**(67,665,351.95)**
2814	**Acc Def Inc Tax-Acc Amort Prop**	2814001	Acc Dfd FIT - FAS 109 Excess		26,847,393.30	26,847,393.30	26,847,393.30	26,962,712.00	26,962,712.00	26,962,712.00
	2814 Total			**-**	**26,847,393.30**	**26,847,393.30**	**26,847,393.30**	**26,962,712.00**	**26,962,712.00**	**26,962,712.00**
2821	**Accum Defd FIT - Utility Prop**	2821001	Accum Defd FIT - Utility Prop	(1,289,625,840.94)	(1,366,840,207.43)	(1,367,235,482.43)	(1,367,460,206.03)	(1,366,785,240.91)	(1,366,909,904.73)	(1,366,854,088.99)
	2821 Total			**(1,289,625,840.94)**	**(1,366,840,207.43)**	**(1,367,235,482.43)**	**(1,367,460,206.03)**	**(1,366,785,240.91)**	**(1,366,909,904.73)**	**(1,366,854,088.99)**
2823	**Accum Defd FIT - Other Prop**	2823001	Acc Dfrd FIT FAS 109 Flow Thru	(92,500,687.87)	(55,141,420.24)	(55,129,472.11)	(55,192,151.97)	(55,277,475.18)	(55,254,165.97)	(55,216,113.80)

Southerwestern Electric Power Company
Trial Balance - Balance Sheet
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

FERC	FERC Title	Account	Description	Actual						
				Balance 12/31/16	Balance 12/31/17	Balance 1/31/18	Balance 2/28/18	Balance 3/31/18	Balance 4/30/18	Balance 5/31/18
	2823 Total			**(92,500,687.87)**	**(55,141,420.24)**	**(55,129,472.11)**	**(55,192,151.97)**	**(55,277,475.18)**	**(55,254,165.97)**	**(55,216,113.80)**
2824	**Accum Defd FIT - Other Prop**	2824001	Acc Dfrd FIT - SFAS 109 Excess	129,454.79	546,503,749.54	546,461,749.54	546,419,749.54	543,746,063.84	542,865,274.84	541,984,485.84
	2824 Total			**129,454.79**	**546,503,749.54**	**546,461,749.54**	**546,419,749.54**	**543,746,063.84**	**542,865,274.84**	**541,984,485.84**
2831	**Accum Deferred FIT - Other**	2831001	Accum Deferred FIT - Other	(61,343,156.88)	(72,816,094.85)	(61,055,580.10)	(60,627,092.66)	(33,939,687.29)	(33,450,318.32)	(33,763,090.05)
		2831002	Accum Deferred SIT - Other	1,297,066.00						
	2831 Total			**(60,046,090.88)**	**(72,816,094.85)**	**(61,055,580.10)**	**(60,627,092.66)**	**(33,939,687.29)**	**(33,450,318.32)**	**(33,763,090.05)**
2832	**Accum Dfrd FIT - Oth Inc & Ded**	2832001	Accum Dfrd FIT - Oth Inc & Ded	(12,413.80)						
	2832 Total			**(12,413.80)**	**-**	**-**	**-**	**-**	**-**	**-**
2833	**Acc Dfd FIT FAS 109 Flow Thru**	2833001	Acc Dfd FIT FAS 109 Flow Thru	(111,452,466.47)	(54,362,641.35)	(54,355,806.92)	(54,371,472.25)	(54,775,860.27)	(54,824,712.38)	(54,822,606.28)
		2833002	Acc Dfrd SIT FAS 109 Flow Thru	(176,520,778.00)	(189,260,844.00)	(189,243,085.00)	(189,238,001.00)	(191,055,315.00)	(191,317,110.00)	(191,354,909.00)
	2833 Total			**(287,973,244.47)**	**(243,623,485.35)**	**(243,598,891.92)**	**(243,609,473.25)**	**(245,831,175.27)**	**(246,141,822.38)**	**(246,177,515.28)**
2834	**Acc Defd FIT - SFAS 109 Excess**	2834001	Acc Defd FIT - SFAS 109 Excess		(8,891,357.29)	(8,888,986.41)	(8,888,986.41)	(8,888,986.41)	(8,888,986.41)	(8,888,986.41)
	2834 Total			**-**	**(8,891,357.29)**	**(8,888,986.41)**	**(8,888,986.41)**	**(8,888,986.41)**	**(8,888,986.41)**	**(8,888,986.41)**
Total	Total				-	-	-	-	-	-
			Assets	**7,250,129,073.20**	**7,386,235,450.54**	**7,722,515,981.36**	**7,691,933,077.31**	**7,427,052,183.38**	**7,443,641,770.55**	**7,487,825,644.62**
			Liabilities	**(7,250,129,073.19)**	**(7,386,235,450.54)**	**(7,722,515,981.36)**	**(7,691,933,077.31)**	**(7,427,052,183.38)**	**(7,443,641,770.55)**	**(7,487,825,644.62)**

Southerwestern Electric Power Company
Trial Balance - Balance Sheet
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by fiscal or calendar years. Also, provide

FERC	FERC Title	Account	Description	Balance 6/30/18	Balance 7/31/18	Forecasted Balance 8/31/18	Balance 9/30/18	Balance 10/31/18	Balance 11/30/18	Balance 12/31/18
1010	**Plant In Service**	1010001	Plant in Service	8,583,352,751.48	8,617,255,078.83	8,621,085,782.28	8,649,436,179.28	8,696,067,434.28	8,734,911,925.28	8,778,418,504.28
		1010006	Dolet Hills FAS 143 ARO Asset	41,520,820.72	41,520,820.72	41,520,820.72	41,520,820.72	41,520,820.72	41,520,820.72	41,520,820.72
	1010 Total			**8,624,873,572.20**	**8,658,775,899.55**	**8,662,606,603.00**	**8,690,957,000.00**	**8,737,588,255.00**	**8,776,432,746.00**	**8,819,939,325.00**
1011	**Property Under Capital Leases**	1011001	Capital Leases	48,251,594.81	47,912,412.58	47,912,413.00	47,912,413.00	47,912,413.00	47,912,413.00	47,912,413.00
		1011006	Prov-Leased Assets	(21,111,121.52)	(21,116,832.29)	(21,116,832.00)	(21,116,832.00)	(21,116,832.00)	(21,116,832.00)	(21,116,832.00)
		1011012	Accrued Capital Leases	134,773.18	124,545.96	124,546.00	124,546.00	124,546.00	124,546.00	124,546.00
	1011 Total			**27,275,246.47**	**26,920,126.25**	**26,920,127.00**	**26,920,127.00**	**26,920,127.00**	**26,920,127.00**	**26,920,127.00**
1050	**Plant Held for Future Use**	1050001	Held For Fut Use	1,291,835.11	1,291,835.11	1,291,835.00	1,291,835.00	1,291,835.00	1,291,835.00	1,291,835.00
	1050 Total			**1,291,835.11**	**1,291,835.11**	**1,291,835.00**	**1,291,835.00**	**1,291,835.00**	**1,291,835.00**	**1,291,835.00**
1060	**Completed Const Not Classifd**	1060001	Const Not Classifd	421,495,946.80	412,274,780.82	412,457,174.00	413,807,037.00	416,027,315.00	417,876,837.00	419,948,338.00
	1060 Total			**421,495,946.80**	**412,274,780.82**	**412,457,174.00**	**413,807,037.00**	**416,027,315.00**	**417,876,837.00**	**419,948,338.00**
1070	**Construction Work In Progress**	1070001	CWIP - Project	218,179,140.72	213,767,956.00	230,488,094.00	237,043,337.00	225,665,282.00	224,623,690.00	208,464,848.00
	1070 Total			**218,179,140.72**	**213,767,956.00**	**230,488,094.00**	**237,043,337.00**	**225,665,282.00**	**224,623,690.00**	**208,464,848.00**
1080	**Accum Prov for Deprec of Plant**	1080001	A/P for Deprec of Plt	(2,513,076,183.82)	(2,523,824,600.86)	(2,529,192,798.00)	(2,542,486,297.00)	(2,555,912,643.00)	(2,569,506,283.00)	(2,572,045,913.00)
		1080005	RWIP - Project Detail	11,137,085.29	12,348,757.98	12,375,024.00	12,440,067.00	12,505,761.00	12,572,273.00	12,584,699.00
		1080011	Cost of Removal Reserve	(439,084,216.80)	(440,807,784.98)	(441,982,335.00)	(442,889,651.00)	(443,813,677.00)	(445,067,997.00)	(446,346,282.00)
		1080012	Dolet Hills FAS 143 ARO Deprec	(6,638,051.74)	(6,794,476.54)	(6,808,928.00)	(6,844,716.00)	(6,880,862.00)	(6,917,458.00)	(6,924,295.00)
		1080013	ARO Removal Deprec - Accretion	6,714,363.21	6,774,365.37	6,792,416.00	6,806,360.00	6,820,560.00	6,839,837.00	6,859,481.00
		1080155	Unrecovered Plant	50,276,783.68	50,276,783.68	50,276,784.00	50,276,784.00	50,276,784.00	50,276,784.00	50,276,784.00
	1080 Total			**(2,890,670,220.18)**	**(2,902,026,955.35)**	**(2,908,539,837.00)**	**(2,922,697,453.00)**	**(2,937,004,077.00)**	**(2,951,802,844.00)**	**(2,955,595,526.00)**
1110	**A/P for Amortization of Plant**	1110001	A/P for Amort of Plt	(48,587,681.11)	(50,016,984.21)	(50,123,371.00)	(50,386,820.00)	(50,652,903.00)	(50,922,301.00)	(50,972,631.00)
	1110 Total			**(48,587,681.11)**	**(50,016,984.21)**	**(50,123,371.00)**	**(50,386,820.00)**	**(50,652,903.00)**	**(50,922,301.00)**	**(50,972,631.00)**
1140	**Plant Acquisition Adjustments**	1140001	Plant Acquisition Adj	18,043,976.22	18,043,976.22	18,043,976.00	18,043,976.00	18,043,976.00	18,043,976.00	18,043,976.00
	1140 Total			**18,043,976.22**	**18,043,976.22**	**18,043,976.00**	**18,043,976.00**	**18,043,976.00**	**18,043,976.00**	**18,043,976.00**
1150	**Amrtz of Plant Acquisition Adj**	1150001	Amrtz of Plt Acqt Adj	(18,043,976.22)	(18,043,976.22)	(18,043,976.00)	(18,043,976.00)	(18,043,976.00)	(18,043,976.00)	(18,043,976.00)
	1150 Total			**(18,043,976.22)**	**(18,043,976.22)**	**(18,043,976.00)**	**(18,043,976.00)**	**(18,043,976.00)**	**(18,043,976.00)**	**(18,043,976.00)**
1160	**Other Plant Adjustments**	1160007	OthElecPltAdjTurkImprmnt-EPIS	(58,411,747.11)	(58,411,747.11)	(58,307,470.00)	(58,203,071.00)	(58,098,551.00)	(57,993,910.00)	(57,889,147.00)
		1160008	TurkAFUDCReverseTXCap-EPIS	(1,313,076.50)	(1,313,076.50)	(1,310,732.00)	(1,308,386.00)	(1,306,036.00)	(1,303,684.00)	(1,301,329.00)
		1160009	AmortTurkImprmnt&AFUDCReversal	6,003,589.10	6,094,028.89	6,083,150.00	6,072,258.00	6,061,354.00	6,050,436.00	6,039,507.00
		1160012	Turk Imprmnt-AuxBoiler	(18,500,000.00)	(18,500,000.00)	(18,466,974.00)	(18,433,909.00)	(18,400,806.00)	(18,367,664.00)	(18,334,484.00)
		1160013	Turk Imprmnt-AuxBoiler Amort	1,949,396.00	1,980,846.00	1,977,310.00	1,973,769.00	1,970,225.00	1,966,676.00	1,963,124.00
		1160016	TX Trans Veg Mgmt Cost Wrteoff	(1,420,452.64)	(1,441,054.14)	(1,438,482.00)	(1,435,906.00)	(1,433,327.00)	(1,430,746.00)	(1,428,161.00)
		1160017	TX Distr Veg Mgmt Cost Wrteoff	(4,103,577.10)	(4,103,577.10)	(4,096,251.00)	(4,088,917.00)	(4,081,574.00)	(4,074,223.00)	(4,066,863.00)
		1160018	TX Dist Veg Mgt WriteOff Amort	301,186.69	310,382.12	309,828.00	309,273.00	308,718.00	308,162.00	307,605.00
		1160019	TX Tran Veg Mgt WriteOff Amort	58,493.83	60,636.20	60,528.00	60,420.00	60,311.00	60,202.00	60,094.00
		1160020	TX Trans Costs - SERP	(159,519.76)	(159,523.31)	(159,239.00)	(158,953.00)	(158,668.00)	(158,382.00)	(158,096.00)
		1160021	TX Distr Costs - SERP	(47,774.86)	(47,811.70)	(47,726.00)	(47,641.00)	(47,555.00)	(47,470.00)	(47,384.00)
		1160022	TX Gen Costs - SERP	(301,357.70)	(300,961.68)	(300,424.00)	(299,886.00)	(299,348.00)	(298,809.00)	(298,269.00)
		1160023	TX CWIP FinBased Incen - Trans	(1,720,206.60)	(1,747,345.47)	(1,744,226.00)	(1,741,103.00)	(1,737,976.00)	(1,734,846.00)	(1,731,712.00)
		1160024	TX CWIP FinBased Incen - Distr	(2,074,269.22)	(2,107,031.67)	(2,103,270.00)	(2,099,504.00)	(2,095,734.00)	(2,091,959.00)	(2,088,180.00)
		1160025	TX CWIP FinBased Incen - Gen	(2,460,164.65)	(2,468,125.88)	(2,463,720.00)	(2,459,309.00)	(2,454,892.00)	(2,450,471.00)	(2,446,044.00)
		1160026	TX RWIP FinBased Incen - Trans	(63,518.80)	(63,897.38)	(63,783.00)	(63,669.00)	(63,555.00)	(63,440.00)	(63,326.00)
		1160027	TX RWIP FinBased Incen - Distr	(81,812.21)	(84,668.54)	(84,517.00)	(84,366.00)	(84,215.00)	(84,063.00)	(83,911.00)
		1160028	TX RWIP FinBased Incen - Gen	(93,789.74)	(94,091.98)	(93,924.00)	(93,756.00)	(93,587.00)	(93,419.00)	(93,250.00)
	1160 Total			**(82,438,601.27)**	**(82,397,019.26)**	**(82,249,922.00)**	**(82,102,656.00)**	**(81,955,216.00)**	**(81,807,610.00)**	**(81,659,826.00)**
1210	**Nonutility Property**	1210001	Nonutility Property - Owned	297,694.16	297,694.16	297,694.00	297,694.00	297,694.00	297,694.00	297,694.00
		1210003	Nonutility Property - WIP	2.10	2.10	2.00	2.00	2.00	2.00	2.00
	1210 Total			**297,696.26**	**297,696.26**	**297,696.00**	**297,696.00**	**297,696.00**	**297,696.00**	**297,696.00**
1220	**Depr & Amort of Nonutil Prop**	1220001	Depr&Amrt of Nonutl Prop-Ownd	64.55	64.55	65.00	65.00	65.00	65.00	65.00
		1220003	Depr&Amrt of Nonutl Prop-WIP	0.00	-					

Southerwestern Electric Power Company
Trial Balance - Balance Sheet
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by fiscal or calendar years. Also, provide

FERC	FERC Title	Account	Description	Balance 6/30/18	Balance 7/31/18	Forecasted Balance 8/31/18	Forecasted Balance 9/30/18	Forecasted Balance 10/31/18	Forecasted Balance 11/30/18	Forecasted Balance 12/31/18
	1220 Total			**64.55**	**64.55**	**65.00**	**65.00**	**65.00**	**65.00**	**65.00**
1231	**Invest in Subsidiary Companies**	1230000	Invest Nonconsol Assoc Co	-	-	326,659.00	574,485.00	806,112.00	958,829.00	1,075,785.00
		1231003	Capital Contributions to Subs	100,000.00	100,000.00	100,000.00	100,000.00	100,000.00	100,000.00	100,000.00
		1231005	Invest in Subs Retained Erngs	1,888,850.63	1,892,064.44	1,892,064.00	1,892,064.00	1,892,064.00	1,892,064.00	1,892,064.00
		1231101	Invest Nonconsol Subs-Equity	24,759,406.87	24,759,406.87	24,759,407.00	24,759,407.00	24,759,407.00	24,759,407.00	24,759,407.00
		1231102	Equity in Erngs Nonconsol Subs	13,496,494.99	13,766,159.31	13,766,159.00	13,766,159.00	13,766,159.00	13,766,159.00	13,766,159.00
	1231 Total			**40,244,752.49**	**40,517,630.62**	**40,844,289.00**	**41,092,115.00**	**41,323,742.00**	**41,476,459.00**	**41,593,415.00**
1240	**Other Investments**	1240002	Oth Investments-Nonassociated	878,008.64	878,008.64	1,071,009.00	1,263,009.00	1,454,009.00	1,644,009.00	1,833,009.00
		1240027	Other Property - RWIP	2,693.74	3,498.28	3,498.00	3,498.00	3,498.00	3,498.00	3,498.00
		1240029	Other Property - CPR	301,443.53	301,443.53	301,444.00	301,444.00	301,444.00	301,444.00	301,444.00
	1240 Total			**1,182,145.91**	**1,182,950.45**	**1,375,951.00**	**1,567,951.00**	**1,758,951.00**	**1,948,951.00**	**2,137,951.00**
1290	**Special Funds**	1290001	Non-UMWA PRW Funded Position	27,855,897.91	27,855,897.91	27,855,898.00	27,855,898.00	27,855,898.00	27,855,898.00	27,855,898.00
		1290002	SFAS 106 - Non-UMWA PRW	3,601,982.60	4,207,040.61	4,207,041.00	4,207,041.00	4,207,041.00	4,207,041.00	4,207,041.00
	1290 Total			**31,457,880.51**	**32,062,938.52**	**32,062,939.00**	**32,062,939.00**	**32,062,939.00**	**32,062,939.00**	**32,062,939.00**
1310	**Cash**	1310000	Cash	2,122,378.37	2,505,236.65	1,625,000.00	1,625,000.00	1,625,000.00	1,625,000.00	1,625,000.00
	1310 Total			**2,122,378.37**	**2,505,236.65**	**1,625,000.00**	**1,625,000.00**	**1,625,000.00**	**1,625,000.00**	**1,625,000.00**
1340	**Other Special Deposits**	1340018	Spec Deposits - Elect Trading	100,219.81	4,560,651.71	4,560,652.00	4,560,652.00	4,560,652.00	4,560,652.00	4,560,652.00
		1340046	Deposits-O&M Dolet Hills Plant	3,044,000.00	3,348,000.00	3,348,000.00	3,348,000.00	3,348,000.00	3,348,000.00	3,348,000.00
		1340048	Spec Deposits-Trading Contra	74,181.00	49,036.00	49,036.00	49,036.00	49,036.00	49,036.00	49,036.00
		1340050	Spec Deposit Mizuho Securities							
		1340051	Spec Depost RBC	-	37,410.90	37,411.00	37,411.00	37,411.00	37,411.00	37,411.00
		1340053	Deposits - Flexible Spending	90,164.07	90,164.07	90,164.00	90,164.00	90,164.00	90,164.00	90,164.00
	1340 Total			**3,308,564.88**	**8,085,262.68**	**8,085,263.00**	**8,085,263.00**	**8,085,263.00**	**8,085,263.00**	**8,085,263.00**
1420	**Customer Accounts Receivable**	1420001	Customer A/R - Electric	126,730,581.45	137,139,619.19	137,139,619.00	137,139,619.00	137,139,619.00	137,139,619.00	137,139,619.00
		1420006	A/R-Customer Assistance	-	-	-	-	-	-	-
		1420014	Customer A/R-System Sales	14,796,181.84	15,272,819.59	15,272,820.00	15,272,820.00	15,272,820.00	15,272,820.00	15,272,820.00
		1420022	Cust A/R - Factored	(129,687,510.80)	(144,670,792.20)	(144,670,792.00)	(144,670,792.00)	(144,670,792.00)	(144,670,792.00)	(144,670,792.00)
		1420023	Cust A/R-System Sales - MLR	145,999.41	251,008.00	251,008.00	251,008.00	251,008.00	251,008.00	251,008.00
		1420044	Customer A/R - Estimated	23,923,508.05	20,640,333.18	20,640,333.00	20,640,333.00	20,640,333.00	20,640,333.00	20,640,333.00
		1420048	Emission Allowance Trading	-	-	-	-	-	-	-
		1420051	MISO AR Accrual	-	-	-	-	-	-	-
		1420055	SPP AR Accrual	444,314.03	(0.00)	-	-	-	-	-
		1420101	Other Accounts Rec - Cust	571,141.95	563,032.56	563,033.00	563,033.00	563,033.00	563,033.00	563,033.00
		1420102	AR Peoplesoft Billing - Cust	4,288,347.61	5,554,690.12	5,554,690.00	5,554,690.00	5,554,690.00	5,554,690.00	5,554,690.00
	1420 Total			**41,212,563.54**	**34,750,710.44**	**34,750,711.00**	**34,750,711.00**	**34,750,711.00**	**34,750,711.00**	**34,750,711.00**
1430	**Other Accounts Receivable**	1430002	Allowances	19.80	19.80	20.00	20.00	20.00	20.00	20.00
		1430022	2001 Employee Biweekly Pay Cnv	7,628.97	7,628.97	7,629.00	7,629.00	7,629.00	7,629.00	7,629.00
		1430080	Jointly Owned Unit O&M Billing	17,035,662.15	18,340,069.42	18,340,069.00	18,340,069.00	18,340,069.00	18,340,069.00	18,340,069.00
		1430081	Damage Recovery - Third Party	55,299.00	80,592.57	80,593.00	80,593.00	80,593.00	80,593.00	80,593.00
		1430083	Damage Recovery Offset Demand	(55,299.00)	(86,478.57)	(86,479.00)	(86,479.00)	(86,479.00)	(86,479.00)	(86,479.00)
		1430086	AR Accrual NYMEX OTC Penults	0.00	0.00	-	-	-	-	-
		1430101	Other Accounts Rec - Misc	1,078,865.56	950,296.78	950,297.00	950,297.00	950,297.00	950,297.00	950,297.00
		1430102	AR Peoplesoft Billing - Misc	2,277,012.58	931,407.48	931,407.00	931,407.00	931,407.00	931,407.00	931,407.00
		1430103	AR Long-Term-Miscellaneous	970,700.87	901,365.10	901,365.00	901,365.00	901,365.00	901,365.00	901,365.00
	1430 Total			**21,369,889.93**	**21,124,901.55**	**21,124,901.00**	**21,124,901.00**	**21,124,901.00**	**21,124,901.00**	**21,124,901.00**
1440	**A/P for Uncollectible Accts-Cr**	1440002	Uncoll Accts-Other Receivables	(557,714.93)	(557,714.93)	(557,715.00)	(557,715.00)	(557,715.00)	(557,715.00)	(557,715.00)
	1440 Total			**(557,714.93)**	**(557,714.93)**	**(557,715.00)**	**(557,715.00)**	**(557,715.00)**	**(557,715.00)**	**(557,715.00)**
1450	**Corp Borrow Prg (NR-Assoc)**	1450000	Corp Borrow Prg (NR-Assoc)	-	-	-	485,089,003.00	48,118,970.00	23,963,025.00	-
	1450 Total			**-**	**-**	**-**	**485,089,003.00**	**48,118,970.00**	**23,963,025.00**	**-**
1460	**Accts Rec from Assoc Cos**	1460001	A/R Assoc Co - InterUnit G/L	30,319,011.20	27,115,186.35	27,115,186.00	27,115,186.00	27,115,186.00	27,115,186.00	27,115,186.00
		1460004	A/R Assoc Co - CM Bills	42,698.70	31,877.62	31,878.00	31,878.00	31,878.00	31,878.00	31,878.00
		1460006	A/R Assoc Co - Intercompany	(1,115,090.59)	1,517,768.66	1,517,769.00	1,517,769.00	1,517,769.00	1,517,769.00	1,517,769.00

Southerwestern Electric Power Company
Trial Balance - Balance Sheet
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by fiscal or calendar years. Also, provide

FERC	FERC Title	Account	Description	Balance 6/30/18	Balance 7/31/18	Forecasted Balance 8/31/18	Forecasted Balance 9/30/18	Forecasted Balance 10/31/18	Forecasted Balance 11/30/18	Forecasted Balance 12/31/18
		1460009	A/R Assoc Co - InterUnit A/P	27,805.13	22,947.89	22,948.00	22,948.00	22,948.00	22,948.00	22,948.00
		1460011	A/R Assoc Co - Multi Pmts	5,247,622.42	10,323,653.40	10,323,653.00	10,323,653.00	10,323,653.00	10,323,653.00	10,323,653.00
		1460025	Fleet - M4 - A/R	28,605.36	16,583.32	16,583.00	16,583.00	16,583.00	16,583.00	16,583.00
	1460 Total			**34,550,652.22**	**39,028,017.24**	**39,028,017.00**	**39,028,017.00**	**39,028,017.00**	**39,028,017.00**	**39,028,017.00**
1510	**Fuel Stock**	1510001	Fuel Stock - Coal	42,362,944.29	45,924,598.61	46,758,028.00	44,050,739.00	43,471,548.00	42,571,313.00	44,950,375.00
		1510002	Fuel Stock - Oil	4,419,035.12	4,591,541.00	4,591,541.00	4,591,541.00	4,591,541.00	4,591,541.00	4,591,541.00
		1510016	Coal Inv on Hand Transp	16,637.21	12,466.02	12,692.00	11,957.00	11,800.00	11,556.00	12,202.00
		1510017	Lignite Inv on Hand Inc Transp	29,848,984.23	27,724,842.51	28,227,987.00	26,593,586.00	26,243,927.00	25,700,452.00	27,136,700.00
		1510018	Coal Survey Adjustment	(1,228,391.33)	(921,293.51)	(938,013.00)	(883,702.00)	(872,083.00)	(854,023.00)	(901,750.00)
		1510020	Fuel Stock Coal - Intransit	5,821,532.61	3,933,566.35	4,004,952.00	3,773,065.00	3,723,456.00	3,646,348.00	3,850,121.00
	1510 Total			**81,240,742.12**	**81,265,720.97**	**82,657,187.00**	**78,137,186.00**	**77,170,189.00**	**75,667,187.00**	**79,639,189.00**
1520	**Fuel Stock Exp Undistributed**	1520000	Fuel Stock Exp Undistributed	2,169,303.77	2,167,937.92	2,167,938.00	2,167,938.00	2,167,938.00	2,167,938.00	2,167,938.00
	1520 Total			**2,169,303.77**	**2,167,937.92**	**2,167,938.00**	**2,167,938.00**	**2,167,938.00**	**2,167,938.00**	**2,167,938.00**
1540	**Materials & Oper Supplies**	1540001	M&S - Regular	66,688,758.69	66,526,150.71	66,526,150.00	66,526,150.00	66,526,150.00	66,526,150.00	66,526,150.00
		1540004	M&S - Exempt Material	518,534.68	516,794.04	516,794.00	516,794.00	516,794.00	516,794.00	516,794.00
		1540006	M&S - Lime and Limestone	1,136,179.74	1,403,683.78	1,403,684.00	1,403,684.00	1,403,684.00	1,403,684.00	1,403,684.00
		1540013	Transportation Inventory	87,065.69	87,065.69	87,066.00	87,066.00	87,066.00	87,066.00	87,066.00
		1540025	Matls Supply-Activated Carbon	441,137.51	298,572.23	298,572.00	298,572.00	298,572.00	298,572.00	298,572.00
		1540028	M&S - Anhydrous Ammonia	31,987.49	18,579.02	18,579.00	18,579.00	18,579.00	18,579.00	18,579.00
		1540030	Matls Supply-Calcium Bromide	59,898.64	57,670.85	57,671.00	57,671.00	57,671.00	57,671.00	57,671.00
	1540 Total			**68,963,562.44**	**68,908,516.32**	**68,908,516.00**	**68,908,516.00**	**68,908,516.00**	**68,908,516.00**	**68,908,516.00**
1581	**Allowance Inventory**	1581012	CSAPR An. NOx Inv. - Current	-	-	(43,935.00)	(99,768.00)	(99,768.00)	(99,768.00)	(99,768.00)
		1581014	CSAPR Seas NOx Comp Inv - Curr	110,236.86	67,068.39	87,858.00	112,608.00	112,608.00	112,608.00	112,608.00
	1581 Total			**110,236.86**	**67,068.39**	**43,923.00**	**12,840.00**	**12,840.00**	**12,840.00**	**12,840.00**
1630	**Stores Expense Undistributed**	1630004	Strs Exp-T&D Satellite Storerm	(0.00)	-	-	-	-	-	-
		1630056	Knox Lee Power Plant	0.00	-	-	-	-	-	-
		1630059	Pirkey Power Plant	(0.00)	-	-	-	-	-	-
		1630061	Welsh Power Plant	0.01	0.01	-	-	-	-	-
	1630 Total			**0.01**	**0.01**	**-**	**-**	**-**	**-**	**-**
1650	**Prepayments**	1650001	Prepaid Insurance	524,248.59	2,063,566.74	2,063,567.00	2,063,567.00	2,063,567.00	2,063,567.00	2,063,567.00
		165000218	Prepaid Taxes	-	-	-	-	-	-	-
		1650005	Prepaid Employee Benefits	-	-	-	-	-	-	-
		1650006	Other Prepayments	17,091,460.88	16,914,733.62	16,914,734.00	16,914,734.00	16,914,734.00	16,914,734.00	16,914,734.00
		1650009	Prepaid Carry Cost-Factored AR	218,771.29	179,616.75	179,617.00	179,617.00	179,617.00	179,617.00	179,617.00
		1650010	Prepaid Pension Benefits	91,572,614.31	90,896,301.15	90,896,301.15	90,896,301.15	90,896,301.15	90,896,301.15	90,896,301.15
		165000218	Prepaid Taxes		1,125,105.28	1,125,105.00	1,125,105.00	1,125,105.00	1,125,105.00	1,125,105.00
		165001116	Prepaid Sales Taxes							
		165001117	Prepaid Sales Taxes	-	-	-	-	-	-	-
		165001118	Prepaid Sales Taxes	1,023,400.00	1,225,200.00	1,225,200.00	1,225,200.00	1,225,200.00	1,225,200.00	1,225,200.00
		165001216	Prepaid Use Taxes							
		165001217	Prepaid Use Taxes	-	-	-	-	-	-	-
		165001218	Prepaid Use Taxes	1,244.91	159.22	159.00	159.00	159.00	159.00	159.00
		165001316	Prepaid Local Franchise Taxes							
		165001317	Prepaid Local Franchise Taxes	-	-	-	-	-	-	-
		165001318	Prepaid Local Franchise Taxes	54,327.41	53,574.95	53,575.00	53,575.00	53,575.00	53,575.00	53,575.00
		1650014	FAS 158 Qual Contra Asset	(91,572,614.31)	(90,896,301.15)	(90,896,301.15)	(90,896,301.15)	(90,896,301.15)	(90,896,301.15)	(90,896,301.15)
		1650016	FAS 112 ASSETS	-	-					
		1650017	Prepayment - Coal	380,465.73	4,200,175.16	4,200,175.00	4,200,175.00	4,200,175.00	4,200,175.00	4,200,175.00
		1650018	Affl Trans Intercon Providers	0.00	0.00	-	-	-	-	-
		1650021	Prepaid Insurance - EIS	965,012.43	3,126,986.33	3,126,986.00	3,126,986.00	3,126,986.00	3,126,986.00	3,126,986.00
		1650023	Prepaid Lease	198,083.68	183,783.68	183,784.00	183,784.00	183,784.00	183,784.00	183,784.00
		1650029	Future Wetlands Credits L-T	300,000.00	300,000.00	300,000.00	300,000.00	300,000.00	300,000.00	300,000.00
		1650030	Other Prepayments - Long Term	1,709,806.12	1,709,806.12	1,709,806.00	1,709,806.00	1,709,806.00	1,709,806.00	1,709,806.00
		1650035	PRW Without MED-D Benefits	27,129,823.01	27,734,881.02	27,734,881.02	27,734,881.02	27,734,881.02	27,734,881.02	27,734,881.02
		1650037	FAS158 Contra-PRW Exclud Med-D	(27,129,823.01)	(27,734,881.02)	(27,734,881.02)	(27,734,881.02)	(27,734,881.02)	(27,734,881.02)	(27,734,881.02)
	1650 Total			**22,466,821.04**	**31,082,707.85**	**31,082,708.00**	**31,082,708.00**	**31,082,708.00**	**31,082,708.00**	**31,082,708.00**

Southerwestern Electric Power Company
Trial Balance - Balance Sheet
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by fiscal or calendar years. Also, provide

FERC	FERC Title	Account	Description	Balance 6/30/18	Balance 7/31/18	Forecasted Balance 8/31/18	Balance 9/30/18	Balance 10/31/18	Balance 11/30/18	Balance 12/31/18
1710	**Interest&Dividends Receivable**	1710010	Interest Under Recover - LA							
		1710048	Interest Receivable -FIT -LT	(19,483.00)	(19,483.00)	(19,483.00)	(19,483.00)	(19,483.00)	(19,483.00)	(19,483.00)
		1710348	Interest Receivable -SIT -LT							
	1710 Total			**(19,483.00)**	**(19,483.00)**	**(19,483.00)**	**(19,483.00)**	**(19,483.00)**	**(19,483.00)**	**(19,483.00)**
1720	**Rents Receivable**	1720000	Rents Receivable	808,671.40	945,418.90	945,419.00	945,419.00	945,419.00	945,419.00	945,419.00
	1720 Total			**808,671.40**	**945,418.90**	**945,419.00**	**945,419.00**	**945,419.00**	**945,419.00**	**945,419.00**
1730	**Accrued Utility Revenues**	1730003	Acrd Utility Rev-West	57,911,515.27	56,833,992.34	56,833,992.00	56,833,992.00	56,833,992.00	56,833,992.00	56,833,992.00
	1730 Total			**57,911,515.27**	**56,833,992.34**	**56,833,992.00**	**56,833,992.00**	**56,833,992.00**	**56,833,992.00**	**56,833,992.00**
1740	**Misc Current & Accrued Assets**	1740000	Misc Current & Accrued Assets	-	-	-	-	-	-	-
	1740 Total			**-**	**-**	**-**	**-**	**-**	**-**	**-**
1750	**Curr. Unreal Gains - NonAffil**	1750001	Curr. Unreal Gains - NonAffil	7,438,163.34	7,768,208.26	7,768,208.00	7,768,208.00	7,768,208.00	7,768,208.00	7,768,208.00
		1750002	Long-Term Unreal Gns - Non Aff	36,834.00	11,622.00	11,622.00	11,622.00	11,622.00	11,622.00	11,622.00
		1750021	S/T Asset MTM Collateral	(65,042.00)	(46,143.00)	(46,143.00)	(46,143.00)	(46,143.00)	(46,143.00)	(46,143.00)
		1750022	L/T Asset MTM Collateral	(9,139.00)	(2,893.00)	(2,893.00)	(2,893.00)	(2,893.00)	(2,893.00)	(2,893.00)
	1750 Total			**7,400,816.34**	**7,730,794.26**	**7,730,794.00**	**7,730,794.00**	**7,730,794.00**	**7,730,794.00**	**7,730,794.00**
1810	**Unamortized Debt Expense**	1810002	Unamort Debt Exp - Inst Pur Cn	23,805.92	21,001.27	20,844.00	30,459.00	30,244.00	30,028.00	29,813.00
		1810003	Unamort Debt Exp Notes Payable	264,148.62	253,062.00	251,170.00	367,029.00	364,434.00	361,838.00	359,243.00
		1810006	Unamort Debt Exp - Sr Unsec Nt	14,034,501.87	13,934,701.81	13,830,512.00	20,210,224.00	20,067,316.00	19,924,408.00	19,781,500.00
		1810102	Unamort Debt Exp-PCB Ins	-	-	-	-	-	-	-
	1810 Total			**14,322,456.40**	**14,208,765.07**	**14,102,526.00**	**20,607,712.00**	**20,461,994.00**	**20,316,274.00**	**20,170,556.00**
1823	**Other Regulatory Assets**	1823000	Other Regulatory Assets	2,700,286.00	2,687,821.00	2,680,857.00	2,673,892.00	2,666,925.00	2,659,957.00	2,652,987.00
		1823010	Energy Efficiency Recovery	3,126,106.89	2,306,630.17	2,300,654.00	2,294,677.00	2,288,698.00	2,282,718.00	2,276,736.00
		1823075	Def Exp Selling Price Variance	2,606,733.65	2,992,376.31	2,984,624.00	2,976,869.00	2,969,113.00	2,961,355.00	2,953,595.00
		1823077	Unreal Loss on Fwd Commitments	1,099,810.83	1,186,645.52	1,183,571.00	1,180,496.00	1,177,420.00	1,174,344.00	1,171,267.00
		1823099	Asset Retirement Obligations	5,159,214.06	5,268,598.96	5,254,949.00	5,241,296.00	5,227,640.00	5,213,981.00	5,200,318.00
		1823108	Reg Asset - Rate Case Expenses	5,675,163.00	5,357,104.17	5,343,225.00	5,329,343.00	5,315,457.00	5,301,568.00	5,287,676.00
		1823149	Unrecovered Fuel Cost - LA	3,227.00	0.00	-	-	-	-	-
		1823150	Unrecovered Fuel Cost - AR	16,031,976.89	15,763,674.15	(1,706,378.00)	(1,232,019.00)	(819,971.00)	(440,294.00)	82,904.00
		1823165	REG ASSET FAS 158 QUAL PLAN	93,785,518.50	93,785,518.50	93,542,541.00	93,299,506.00	93,056,415.00	92,813,265.00	92,570,059.00
		1823166	REG ASSET FAS 158 OPEB PLAN	(2,340,980.79)	(2,340,980.79)	(2,334,916.00)	(2,328,849.00)	(2,322,782.00)	(2,316,712.00)	(2,310,642.00)
		1823167	REG Asset FAS 158 SERP Plan	1,101,194.50	1,101,194.50	1,098,342.00	1,095,488.00	1,092,634.00	1,089,779.00	1,086,923.00
		1823180	Deferred Storm Expense	(0.00)	-	-	-	-	-	-
		1823219	Under Recovered EAC - LA	189,578.99	166,885.90	(18,065.00)	(13,043.00)	(8,681.00)	(4,661.00)	878.00
		1823241	Valley District Due Diligence	-	0.00	-	-	-	-	-
		1823299	SFAS 106 Medicare Subsidy	3,466,513.39	3,422,070.89	3,413,205.00	3,404,337.00	3,395,467.00	3,386,595.00	3,377,721.00
		1823301	SFAS 109 Flow Thru Defd FIT	69,598,451.25	69,501,853.26	69,501,853.00	69,501,853.00	69,501,853.00	69,501,853.00	69,501,853.00
		1823302	SFAS 109 Flow Thru Defrd SIT	190,948,243.00	191,121,231.00	191,121,231.00	191,121,231.00	191,121,231.00	191,121,231.00	191,121,231.00
		1823306	Net CCS FEED Study Costs	446,858.73	446,858.73	445,701.00	444,543.00	443,385.00	442,226.00	441,067.00
		1823324	LA FRP Asset	128,008.15	120,157.51	119,846.00	119,535.00	119,223.00	118,912.00	118,600.00
		1823348	Louisiana Vegetation Managemnt	(0.00)	(0.00)	-	-	-	-	-
		1823359	SWEPCo Transmission Recovery	2,720,335.45	2,448,301.90	2,441,959.00	2,435,614.00	2,429,268.00	2,422,921.00	2,416,572.00
		1823360	2010 Severance Costs	-	0.00	-	-	-	-	-
		1823374	Environmental Chemical Cost-AR	2,616,570.34	2,710,958.77	2,703,935.00	2,696,910.00	2,689,883.00	2,682,855.00	2,675,825.00
		1823377	NBV - AROs Retired Plants	504,633.69	504,040.35	502,734.00	501,428.00	500,122.00	498,815.00	497,508.00
		1823424	LA 2015 FRP Asset-SPP Deferral	5,053,550.92	5,095,230.51	5,082,030.00	5,068,826.00	5,055,619.00	5,042,409.00	5,029,196.00
		1823425	LA 2015 FRP Asset - Contra	(258,643.64)	(278,118.20)	(277,398.00)	(276,677.00)	(275,956.00)	(275,235.00)	(274,514.00)
		1823428	Welsh 2 TX Portion Undepr Bal	17,333,481.51	17,292,607.89	17,247,807.00	17,202,995.00	17,158,172.00	17,113,339.00	17,068,496.00
		1823539	Facilities Maint SWEPCO LA	664,020.75	665,697.46	663,973.00	662,248.00	660,522.00	658,796.00	657,070.00
		1823554	WELSH/FLINT CREEK ENVIRONM DEF	22,733,836.16	22,596,885.34	22,538,342.00	22,479,785.00	22,421,213.00	22,362,629.00	22,304,030.00
		1823555	WELSH/FLINTCREEK ENVIR-CONTRA	(7,951,652.73)	(7,903,751.21)	(7,883,274.00)	(7,862,793.00)	(7,842,306.00)	(7,821,815.00)	(7,801,319.00)
	1823 Total			**437,142,036.50**	**436,019,492.60**	**417,951,348.00**	**418,017,491.00**	**418,020,564.00**	**417,990,831.00**	**418,106,037.00**
1830	**Prelimin Surv&Investgtn Chrgs**	1830000	Prelimin Surv&Investgtn Chrgs	1,544,920.48	1,668,269.01	1,668,269.00	1,668,269.00	1,668,269.00	1,668,269.00	1,668,269.00
	1830 Total			**1,544,920.48**	**1,668,269.01**	**1,668,269.00**	**1,668,269.00**	**1,668,269.00**	**1,668,269.00**	**1,668,269.00**
1840	**Clearing Accounts**	1840002	Accounts Pay Adj - Clearing	-	(3,195.44)	(3,195.00)	(3,195.00)	(3,195.00)	(3,195.00)	(3,195.00)
		1840019	CMS & CMF - Clearing Activity	(0.00)	-	-	-	-	-	-

Southerwestern Electric Power Company
Trial Balance - Balance Sheet
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by fiscal or calendar years. Also, provide

FERC	FERC Title	Account	Description	Balance 6/30/18	Balance 7/31/18	Forecasted Balance 8/31/18	Balance 9/30/18	Balance 10/31/18	Balance 11/30/18	Balance 12/31/18
		1840033	Alliance Rail Car - OH	65,143.64	101,172.46	101,172.00	101,172.00	101,172.00	101,172.00	101,172.00
		1840035	IT Oper Company (OPCO) Clearng	(0.00)	-	-	-	-	-	-
	1840 Total			**65,143.63**	**97,977.02**	**97,977.00**	**97,977.00**	**97,977.00**	**97,977.00**	**97,977.00**
1860	**MDD-Internal Billing Only**	1860001	Allowances	1,417.03	1,417.03	1,417.00	1,417.00	1,417.00	1,417.00	1,417.00
		1860002	Deferred Expenses	691.88	(11,568.68)	(11,569.00)	(11,569.00)	(11,569.00)	(11,569.00)	(11,569.00)
		186000316	Deferred Property Taxes							
		186000318	Deferred Property Taxes	31,557,855.67	26,298,280.67	20,901,968.00	15,505,655.00	10,109,342.00	4,713,029.00	(683,284.00)
		1860005	Unidentified Cash Receipts	-	(100.00)	(100.00)	(100.00)	(100.00)	(100.00)	(100.00)
		1860007	Billings and Deferred Projects	3,469,660.46	3,627,130.08	3,621,566.00	3,616,003.00	3,764,911.00	3,756,008.00	3,747,320.00
		1860015	Billings Paid Union Benefits	-	2,473.12	2,473.00	2,473.00	2,473.00	2,473.00	2,473.00
		1860046	Railroad Cars Subleased	-	7,848.00	7,848.00	7,848.00	7,848.00	7,848.00	7,848.00
		1860077	Agency Fees - Factored A/R	3,777,378.19	4,001,983.68	4,001,984.00	4,001,984.00	4,001,984.00	4,001,984.00	4,001,984.00
		186008118	Defd Property Tax - Cap Lease	86,498.00	72,081.00	57,290.00	42,499.00	27,709.00	12,918.00	(1,873.00)
		1860089	Reclamation Advance	13,977,984.53	13,408,216.38	13,408,216.00	13,408,216.00	13,408,216.00	13,408,216.00	13,408,216.00
		1860150	Deferred Rate Case Expense	72,947.89	92,947.89	92,948.00	92,948.00	92,948.00	92,948.00	92,948.00
		1860153	Unamortized Credit Line Fees	387,719.79	373,945.59	373,946.00	373,946.00	373,946.00	373,946.00	373,946.00
		1860154	Affl Deferred Tran(IPP) Credit	-	-	-	-	-	-	-
		1860156	Sabine Mine Rusk Preparation	13,533,287.31	13,483,530.82	13,483,531.00	13,483,531.00	13,483,531.00	13,483,531.00	13,483,531.00
		1860160	Deferred Expenses - Current	324,860.85	424,483.96	424,484.00	424,484.00	424,484.00	424,484.00	424,484.00
		1860166	Def Lease Assets - Non Taxable	16,970.87	16,970.87	16,971.00	16,971.00	16,971.00	16,971.00	16,971.00
		1860171	Marshall South Mine Prep	-	(0.00)	-	-	-	-	-
		1860185	Long Term Assoc AR	1,266,807.50	1,266,807.50	1,266,807.00	1,266,807.00	1,266,807.00	1,266,807.00	1,266,807.00
	1860 Total			**68,474,079.96**	**63,066,447.90**	**57,649,780.00**	**52,233,113.00**	**46,970,918.00**	**41,550,911.00**	**36,131,119.00**
1890	**Unamrtzd Loss on Recqd Debt**	1890001	Loss Recqd Debt - FMB	2,247,541.94	2,230,333.49	2,219,368.00	2,208,403.00	2,197,438.00	2,186,472.00	2,175,507.00
		1890002	Loss Rec Debt-Ins Purch Cont	162,513.71	158,425.15	157,646.00	156,867.00	156,088.00	155,310.00	154,531.00
		1890004	Loss Rec Debt-Debentures	1,963,510.39	1,943,853.43	1,934,297.00	1,924,740.00	1,915,183.00	1,905,626.00	1,896,069.00
	1890 Total			**4,373,566.04**	**4,332,612.07**	**4,311,311.00**	**4,290,010.00**	**4,268,709.00**	**4,247,408.00**	**4,226,107.00**
1900	**Accum Deferred Income Taxes**	1900011	ADIT Federal Non-UMWA PRW OCI	(417,286.10)	(417,286.10)	(417,286.00)	(417,286.00)	(417,286.00)	(417,286.00)	(417,286.00)
		1900015	ADIT-Fed-Hdg-CF-Int Rate	1,665,021.53	1,626,300.11	1,626,300.00	1,626,300.00	1,626,300.00	1,626,300.00	1,626,300.00
	1900 Total			**1,247,735.43**	**1,209,014.01**	**1,209,014.00**	**1,209,014.00**	**1,209,014.00**	**1,209,014.00**	**1,209,014.00**
1901	**Accum Deferred FIT - Other**	1901001	Accum Deferred FIT - Other	64,313,249.32	65,590,230.70	65,590,231.00	65,590,231.00	65,590,231.00	65,590,231.00	65,590,231.00
		1901002	Accum Deferred SIT - Other	47,097,817.16	47,097,817.16	47,097,817.00	47,097,817.00	47,097,817.00	47,097,817.00	47,097,817.00
	1901 Total			**111,411,066.48**	**112,688,047.86**	**112,688,048.00**	**112,688,048.00**	**112,688,048.00**	**112,688,048.00**	**112,688,048.00**
1902	**Accum Defd FIT - Oth Inc & Ded**	1902001	Accum Defd FIT - Oth Inc & Ded	809,004.82	673,974.82	673,975.00	673,975.00	673,975.00	673,975.00	673,975.00
	1902 Total			**809,004.82**	**673,974.82**	**673,975.00**	**673,975.00**	**673,975.00**	**673,975.00**	**673,975.00**
1903	**Acc Dfd FIT - FAS109 Flow Thru**	1903001	Acc Dfd FIT - FAS109 Flow Thru	41,628,921.29	41,633,476.03	41,633,476.00	41,633,476.00	41,633,476.00	41,633,476.00	41,633,476.00
	1903 Total			**41,628,921.29**	**41,633,476.03**	**41,633,476.00**	**41,633,476.00**	**41,633,476.00**	**41,633,476.00**	**41,633,476.00**
1904	**Accum Dfd FIT - FAS 109 Excess**	1904001	Accum Dfd FIT - FAS 109 Excess	148,642,099.63	148,407,965.83	148,407,966.00	148,407,966.00	148,407,966.00	148,407,966.00	148,407,966.00
	1904 Total			**148,642,099.63**	**148,407,965.83**	**148,407,966.00**	**148,407,966.00**	**148,407,966.00**	**148,407,966.00**	**148,407,966.00**
2010	**Common Stock Issued**	2010001	Common Stock Issued-Affiliated	(135,659,520.00)	(135,659,520.00)	(136,041,240.00)	(137,497,326.00)	(137,660,425.00)	(137,064,238.00)	(137,747,342.00)
	2010 Total			**(135,659,520.00)**	**(135,659,520.00)**	**(136,041,240.00)**	**(137,497,326.00)**	**(137,660,425.00)**	**(137,064,238.00)**	**(137,747,342.00)**
2100	**Gain Rsle/Cancl Req Cap Stock**	2100000	Gain Rsle/Cancl Req Cap Stock	(2,106,937.41)	(2,106,937.41)	(2,112,866.00)	(2,135,481.00)	(2,138,014.00)	(2,128,754.00)	(2,139,364.00)
	2100 Total			**(2,106,937.41)**	**(2,106,937.41)**	**(2,112,866.00)**	**(2,135,481.00)**	**(2,138,014.00)**	**(2,128,754.00)**	**(2,139,364.00)**
2110	**Miscellaneous Paid-In Capital**	2110000	Miscellaneous Paid-In Capital	(674,443,763.79)	(674,443,763.79)	(676,341,520.00)	(683,580,587.00)	(684,391,446.00)	(681,427,448.00)	(684,823,563.00)
	2110 Total			**(674,443,763.79)**	**(674,443,763.79)**	**(676,341,520.00)**	**(683,580,587.00)**	**(684,391,446.00)**	**(681,427,448.00)**	**(684,823,563.00)**
2160	**Unappropriatd Retnd Earngs**	2160001	Unapprp Retnd Erngs-Unrstrictd	(1,444,271,391.04)	(1,476,407,143.16)	(1,480,561,471.00)	(1,496,408,323.00)	(1,498,183,352.00)	(1,491,694,943.00)	(1,499,129,288.00)
	2160 Total			**(1,444,271,391.04)**	**(1,476,407,143.16)**	**(1,480,561,471.00)**	**(1,496,408,323.00)**	**(1,498,183,352.00)**	**(1,491,694,943.00)**	**(1,499,129,288.00)**
4380	**Div Declrd - Common Stock**	4380001	Div Declrd - Common Stk - Asso	40,000,000.00	40,000,000.00	40,112,552.00	40,541,888.00	40,589,978.00	40,414,189.00	40,615,606.00
	4380 Total			**40,000,000.00**	**40,000,000.00**	**40,112,552.00**	**40,541,888.00**	**40,589,978.00**	**40,414,189.00**	**40,615,606.00**
4390	**Adj to Retained Earnings**	4390000	Adj to Retained Earnings	399,934.61	399,934.61	401,060.00	405,353.00	405,833.00	404,076.00	406,090.00

Southerwestern Electric Power Company
Trial Balance - Balance Sheet
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by fiscal or calendar years. Also, provide

FERC	FERC Title	Account	Description	Balance 6/30/18	Balance 7/31/18	Forecasted Balance 8/31/18	Forecasted Balance 9/30/18	Forecasted Balance 10/31/18	Forecasted Balance 11/30/18	Forecasted Balance 12/31/18
	4390 Total			**399,934.61**	**399,934.61**	**401,060.00**	**405,353.00**	**405,833.00**	**404,076.00**	**406,090.00**
2161	**Unapprp Undistrbutd Sub Erngs**	2161001	Unap Undist Consol Sub Erng	(11,406,570.86)	(11,406,570.86)	(11,438,667.00)	(11,561,098.00)	(11,574,812.00)	(11,524,683.00)	(11,582,120.00)
		2161002	Unap Undist Nonconsol Sub Erng	(20,337,917.51)	(20,337,917.51)	(20,395,145.00)	(20,613,439.00)	(20,637,891.00)	(20,548,511.00)	(20,650,921.00)
	2161 Total			**(31,744,488.37)**	**(31,744,488.37)**	**(31,833,812.00)**	**(32,174,537.00)**	**(32,212,703.00)**	**(32,073,194.00)**	**(32,233,041.00)**
2190	**OCI - FAS 133**	2190007	OCI-Min Pen Liab FAS 158-OPEB	(1,569,790.61)	(1,569,790.61)	(1,527,219.00)	(825,594.00)	(777,576.00)	(729,557.00)	(681,539.00)
		2190015	Accum OCI-Hdg-CF-Int Rate	6,263,652.25	6,117,985.90	5,952,071.00	3,217,608.00	3,030,466.00	2,843,323.00	2,656,181.00
	2190 Total			**4,693,861.64**	**4,548,195.29**	**4,424,852.00**	**2,392,014.00**	**2,252,890.00**	**2,113,766.00**	**1,974,642.00**
2240	**Other Long Term Debt**	2240002	Installment Purchase Contracts	-	-	-	-	-	-	-
		2240005	Other Long Term Debt - Other	(115,000,000.00)	(115,000,000.00)	(115,000,000.00)	(148,228,643.00)	(125,113,065.00)	(125,113,065.00)	(125,113,065.00)
		2240006	Senior Unsecured Notes	(1,875,000,000.00)	(1,875,000,000.00)	(1,875,000,000.00)	(2,416,771,357.00)	(2,039,886,935.00)	(2,039,886,935.00)	(2,039,886,935.00)
		2240502	Instl Purchase Contracts-Curr	(53,500,000.00)	(53,500,000.00)	(53,500,000.00)	(53,500,000.00)	(53,500,000.00)	(53,500,000.00)	(53,500,000.00)
		2240505	Oth LTD - Other - Current							
		2240506	Senior Unsecured Notes-Current	(400,000,000.00)	(400,000,000.00)	(400,000,000.00)	(400,000,000.00)	(400,000,000.00)	(400,000,000.00)	(400,000,000.00)
	2240 Total			**(2,443,500,000.00)**	**(2,443,500,000.00)**	**(2,443,500,000.00)**	**(3,018,500,000.00)**	**(2,618,500,000.00)**	**(2,618,500,000.00)**	**(2,618,500,000.00)**
2260	**Unam Disc LTD - Debit**	2260006	Unam Disc LTD-Dr-Sr Unsec Note	5,024,640.09	4,994,847.27	4,985,429.00	4,976,010.00	4,966,591.00	4,957,172.00	4,947,754.00
	2260 Total			**5,024,640.09**	**4,994,847.27**	**4,985,429.00**	**4,976,010.00**	**4,966,591.00**	**4,957,172.00**	**4,947,754.00**
2270	**Obligatns Undr Cap Lse-Noncurr**	2270001	Obligatns Undr Cap Lse-Noncurr	(23,106,161.28)	(22,886,956.33)	(22,886,956.00)	(22,886,956.00)	(22,886,956.00)	(22,886,956.00)	(18,931,701.00)
		2270003	Accrued Noncur Lease Oblig	(107,818.55)	(99,636.68)	(99,637.00)	(99,637.00)	(99,637.00)	(99,637.00)	(82,418.00)
	2270 Total			**(23,213,979.83)**	**(22,986,593.01)**	**(22,986,593.00)**	**(22,986,593.00)**	**(22,986,593.00)**	**(22,986,593.00)**	**(19,014,119.00)**
2282	**Accm Prov for Injuries&Damages**	2282003	Accm Prv I/D - Worker's Com	(114,032.75)	(87,518.96)	(87,519.00)	(87,519.00)	(87,519.00)	(87,519.00)	(87,519.00)
	2282 Total			**(114,032.75)**	**(87,518.96)**	**(87,519.00)**	**(87,519.00)**	**(87,519.00)**	**(87,519.00)**	**(87,519.00)**
2283	**Accm Prv for Pensions&Benefits**	2283000	Accm Prv for Pensions&Benefits	(1,113,210.11)	(1,120,278.07)	(1,192,827.00)	(1,265,377.00)	(1,337,926.00)	(1,410,475.00)	(1,483,024.00)
		2283001	Deferred Compensation Plan	(1,695,071.49)	(1,695,071.49)	(1,804,844.00)	(1,914,617.00)	(2,024,390.00)	(2,134,163.00)	(2,243,936.00)
		2283002	Supplemental Savings Plan	(1,070,507.75)	(1,059,457.86)	(1,128,068.00)	(1,196,679.00)	(1,265,289.00)	(1,333,900.00)	(1,402,510.00)
		2283005	SFAS 112 Postemployment Benef	(4,042,857.19)	(4,042,857.19)	(4,304,673.00)	(4,566,488.00)	(4,828,304.00)	(5,090,119.00)	(5,351,935.00)
		2283006	SFAS 87 - Pensions	(4,057,878.98)	(4,734,192.14)	(5,040,779.00)	(5,347,365.00)	(5,653,951.00)	(5,960,538.00)	(6,267,124.00)
		2283007	Perf Share Incentive Plan	0.00	-	-	-	-	-	-
		2283013	Incentive Comp Deferral Plan	(171,571.67)	(135,849.99)	(144,648.00)	(153,445.00)	(162,243.00)	(171,041.00)	(179,838.00)
		2283015	FAS 158 SERP Payable Long Term	(950,673.50)	(950,673.50)	(1,012,239.00)	(1,073,805.00)	(1,135,370.00)	(1,196,936.00)	(1,258,502.00)
		2283016	FAS 158 Qual Payable Long Term	1,844,974.79	1,844,974.79	1,964,455.00	2,083,936.00	2,203,417.00	2,322,897.00	2,442,378.00
	2283 Total			**(11,256,795.90)**	**(11,893,405.45)**	**(12,663,623.00)**	**(13,433,840.00)**	**(14,204,056.00)**	**(14,974,275.00)**	**(15,744,491.00)**
2290	**Acc Prov for Rate Refunds**	2290002	Acc Prv Rate Refnds-Nonassoc	(7,717,896.66)	(6,211,117.27)	(6,674,024.00)	(7,059,016.00)	(6,922,531.00)	(6,786,046.00)	(6,649,561.00)
		2290006	Acc Prv for Potential Refund	-	0.00	-	-	-	-	-
		2290018	Acc Prov Refunds - Tax Reform	(24,164,479.02)	(29,008,073.17)	(31,170,010.00)	(32,968,055.00)	(32,330,623.00)	(31,693,190.00)	(31,055,758.00)
		2290019	Acc Prov Refund-Excess Protect	(7,015,015.64)	(8,184,184.92)	(8,794,142.00)	(9,301,433.00)	(9,121,592.00)	(8,941,750.00)	(8,761,908.00)
	2290 Total			**(38,897,391.32)**	**(43,403,375.36)**	**(46,638,176.00)**	**(49,328,504.00)**	**(48,374,746.00)**	**(47,420,986.00)**	**(46,467,227.00)**
2300	**Asset Retirement Obligations**	2300001	Asset Retirement Obligations	(101,811,097.52)	(101,333,094.89)	(101,425,251.00)	(101,518,300.00)	(101,612,248.00)	(101,707,100.00)	(101,802,860.00)
		2300002	ARO - Current	(12,595,938.50)	(12,595,938.50)	(12,607,394.00)	(12,618,960.00)	(12,630,638.00)	(12,642,428.00)	(12,654,331.00)
	2300 Total			**(114,407,036.02)**	**(113,929,033.39)**	**(114,032,645.00)**	**(114,137,260.00)**	**(114,242,886.00)**	**(114,349,528.00)**	**(114,457,191.00)**
2320	**Accounts Payable**	2320001	Accounts Payable - Regular	(26,742,400.65)	(19,812,013.18)	(19,812,013.00)	(19,812,013.00)	(19,812,013.00)	(19,812,013.00)	(19,812,013.00)
		2320002	Unvouchered Invoices	(21,412,467.15)	(21,336,094.43)	(21,336,094.00)	(21,336,094.00)	(21,336,094.00)	(21,336,094.00)	(21,336,094.00)
		2320003	Retention	(7,152,576.68)	(7,191,768.63)	(7,191,769.00)	(7,191,769.00)	(7,191,769.00)	(7,191,769.00)	(7,191,769.00)
		2320008	Miscellaneous Liabilities							
		2320011	Uninvoiced Fuel	(22,031,052.78)	(26,631,678.46)	(26,631,678.00)	(26,631,678.00)	(26,631,678.00)	(26,631,678.00)	(26,631,678.00)
		2320052	Accounts Payable - Purch Power	(13,858,531.79)	(8,541,661.45)	(8,541,661.00)	(8,541,661.00)	(8,541,661.00)	(8,541,661.00)	(8,541,661.00)
		2320054	Emission Allowance Trading	(46,175.00)	1,325.00	1,325.00	1,325.00	1,325.00	1,325.00	1,325.00
		2320062	Broker Fees Payable	(3,514.98)	(4,139.98)	(4,140.00)	(4,140.00)	(4,140.00)	(4,140.00)	(4,140.00)
		2320066	A/P - OPEN ACCESS TRANS EXP	(11,854,137.96)	(11,671,842.30)	(11,671,842.00)	(11,671,842.00)	(11,671,842.00)	(11,671,842.00)	(11,671,842.00)
		2320075	Unvouch - Dolet Hills - Cleco	(1,491,414.32)	(1,486,926.84)	(1,486,927.00)	(1,486,927.00)	(1,486,927.00)	(1,486,927.00)	(1,486,927.00)
		2320076	Corporate Credit Card Liab	(268,169.42)	(196,635.54)	(196,636.00)	(196,636.00)	(196,636.00)	(196,636.00)	(196,636.00)
		2320077	INDUS Unvouchered Liabilities	(3,082,483.58)	(1,554,784.47)	(1,554,784.00)	(1,554,784.00)	(1,554,784.00)	(1,554,784.00)	(1,554,784.00)
		2320089	Mattison-Centerpoint Payable	(7,943,665.50)	(8,773,177.44)	(8,773,177.00)	(8,773,177.00)	(8,773,177.00)	(8,773,177.00)	(8,773,177.00)
		2320090	MISO AP Accrual	(624,030.10)	(642,667.30)	(642,667.00)	(642,667.00)	(642,667.00)	(642,667.00)	(642,667.00)

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FERC	FERC Title	Account	Description	Balance 6/30/18	Balance 7/31/18	Forecasted Balance 8/31/18	Forecasted Balance 9/30/18	Forecasted Balance 10/31/18	Forecasted Balance 11/30/18	Forecasted Balance 12/31/18
	2320 Total			**(116,510,619.91)**	**(107,842,065.02)**	**(107,842,063.00)**	**(107,842,063.00)**	**(107,842,063.00)**	**(107,842,063.00)**	**(107,842,063.00)**
2330	**Corp Borrow Program (NP-Assoc)**	2330000	Corp Borrow Program (NP-Assoc)	(119,910,260.93)	(106,690,962.34)	(102,176,076.00)	-	-	-	(8,615,140.00)
	2330 Total			**(119,910,260.93)**	**(106,690,962.34)**	**(102,176,076.00)**	**-**	**-**	**-**	**(8,615,140.00)**
2340	**Accounts Pay to Assoc Co**	2340001	A/P Assoc Co - InterUnit G/L	(38,688,364.60)	(34,865,728.14)	(34,865,728.00)	(34,865,728.00)	(34,865,728.00)	(34,865,728.00)	(34,865,728.00)
		2340025	A/P Assoc Co - CM Bills	(8,605.80)	(31,051.36)	(31,051.00)	(31,051.00)	(31,051.00)	(31,051.00)	(31,051.00)
		2340027	A/P Assoc Co - Intercompany	(240,125.64)	(218,189.19)	(218,189.00)	(218,189.00)	(218,189.00)	(218,189.00)	(218,189.00)
		2340029	A/P Assoc Co - AEPSC Bills	(12,914,059.58)	(15,113,836.75)	(15,113,837.00)	(15,113,837.00)	(15,113,837.00)	(15,113,837.00)	(15,113,837.00)
		2340030	A/P Assoc Co - InterUnit A/P	(64,647.01)	(63,565.52)	(63,566.00)	(63,566.00)	(63,566.00)	(63,566.00)	(63,566.00)
		2340032	A/P Assoc Co - Multi Pmts	(5,331.37)	(13,581.56)	(13,582.00)	(13,582.00)	(13,582.00)	(13,582.00)	(13,582.00)
		2340033	A/P Assoc Co - Factored A/R	(59,181,390.28)	(55,428,381.56)	(55,428,382.00)	(55,428,382.00)	(55,428,382.00)	(55,428,382.00)	(55,428,382.00)
		2340035	Fleet - M4 - A/P	(18,071.74)	(8,250.03)	(8,250.00)	(8,250.00)	(8,250.00)	(8,250.00)	(8,250.00)
		2340041	A/P Assc Co - Non-InterUnit GL	(16,381,833.25)	(14,903,072.32)	(14,903,072.00)	(14,903,072.00)	(14,903,072.00)	(14,903,072.00)	(14,903,072.00)
	2340 Total			**(127,502,429.27)**	**(120,645,656.43)**	**(120,645,657.00)**	**(120,645,657.00)**	**(120,645,657.00)**	**(120,645,657.00)**	**(120,645,657.00)**
2350	**Customer Deposits**	2350001	Customer Deposits-Active	(64,008,830.67)	(63,929,187.30)	(63,929,187.00)	(63,929,187.00)	(63,929,187.00)	(63,929,187.00)	(63,929,187.00)
		2350003	Deposits - Trading Activity	(16,428.67)	0.00	-	-	-	-	-
	2350 Total			**(64,025,259.34)**	**(63,929,187.30)**	**(63,929,187.00)**	**(63,929,187.00)**	**(63,929,187.00)**	**(63,929,187.00)**	**(63,929,187.00)**
2360	**Taxes Accrued**	2360001	Federal Income Tax	10,344,095.12	5,434,101.79	5,619,940.00	5,754,782.00	4,817,263.00	4,475,653.00	2,363,156.00
		236000215	State Income Taxes	12,320.00	12,320.00	12,741.00	13,047.00	10,922.00	10,147.00	5,358.00
		236000216	State Income Taxes							
		236000217	State Income Taxes	845,451.16	845,451.16	874,364.00	895,343.00	749,482.00	696,333.00	367,666.00
		236000218	State Income Taxes	(826,322.19)	(2,332,721.18)	(2,412,497.00)	(2,470,381.00)	(2,067,928.00)	(1,921,284.00)	(1,014,443.00)
		2360004	FICA	(374,261.09)	(462,940.37)	(478,772.00)	(490,260.00)	(410,391.00)	(381,289.00)	(201,321.00)
		2360005	Federal Unemployment Tax	(1,351.58)	(708.12)	(732.00)	(750.00)	(628.00)	(583.00)	(308.00)
		2360006	State Unemployment Tax	(1,416.05)	(779.77)	(806.00)	(826.00)	(691.00)	(642.00)	(339.00)
		236000700	State Sales and Use Taxes	-	-	-	-	-	-	-
		236000716	State Sales and Use Taxes	-	-	-	-	-	-	-
		236000717	State Sales and Use Taxes	179,765.99	263,276.62	272,280.00	278,813.00	233,391.00	216,841.00	114,492.00
		236000718	State Sales and Use Taxes	(1,117,260.37)	(1,147,408.66)	(1,186,648.00)	(1,215,120.00)	(1,017,163.00)	(945,033.00)	(498,980.00)
		236000816	Real Personal Property Taxes							
		236000817	Real Personal Property Taxes	(7,470,471.08)	(7,475,761.08)	(7,731,421.00)	(7,916,925.00)	(6,627,168.00)	(6,157,212.00)	(3,251,023.00)
		236000818	Real Personal Property Taxes	(64,324,692.00)	(64,324,692.00)	(66,524,497.00)	(68,120,660.00)	(57,023,030.00)	(52,979,321.00)	(27,973,216.00)
		236001205	State Franchise Taxes	-		-	-	-	-	-
		236001216	State Franchise Taxes							
		236001217	State Franchise Taxes	363,855.99	363,855.99	376,299.00	385,328.00	322,554.00	299,680.00	158,232.00
		236001218	State Franchise Taxes	2,672,000.00	1,505,000.00	1,556,469.00	1,593,814.00	1,334,164.00	1,239,553.00	654,487.00
		236002016	State Public Service Com Tax							
		236002017	State Public Service Com Tax	(1,436,652.00)	(1,436,652.00)	(1,485,783.00)	(1,521,433.00)	(1,273,574.00)	(1,183,260.00)	(624,764.00)
		236002018	State Public Service Com Tax	(120,000.00)	(291,721.00)	(301,697.00)	(308,936.00)	(258,607.00)	(240,268.00)	(126,862.00)
		236002206	State License/Registration Tax	-	-	-	-	-	-	-
		236002208	State License/Registration Tax	-	-	-	-	-	-	-
		236002516	Local Franchise Tax							
		236002517	Local Franchise Tax	-	-	-	-	-	-	-
		236002518	Local Franchise Tax	(3,943,187.37)	(1,975,254.98)	(2,042,806.00)	(2,091,820.00)	(1,751,039.00)	(1,626,866.00)	(858,989.00)
		236003316	Pers Prop Tax-Cap Leases							
		236003317	Pers Prop Tax-Cap Leases	-	(8,492.63)	(8,783.00)	(8,994.00)	(7,529.00)	(6,995.00)	(3,693.00)
		236003318	Pers Prop Tax-Cap Leases	(173,000.00)	(173,000.00)	(178,916.00)	(183,209.00)	(153,362.00)	(142,487.00)	(75,233.00)
		2360037	FICA - Incentive accrual	(440,803.00)	(524,209.85)	(542,137.00)	(555,145.00)	(464,705.00)	(431,751.00)	(227,966.00)
		2360501	Fed Inc Tax-Short Term FIN48	247,135.74	0.00	-	-	-	-	-
		2360502	State Inc Tax-Short Term FIN48	(53,646.00)	(53,646.00)	(55,481.00)	(56,812.00)	(47,557.00)	(44,184.00)	(23,329.00)
		2360601	Fed Inc Tax-Long Term FIN48	(432,721.00)	-	-	-	-	-	-
		2360602	State Inc Tax-Long Term FIN48	761,734.00	761,734.00	787,784.00	806,686.00	675,268.00	627,382.00	331,259.00
		2360701	SEC Accum Defd FIT-Util FIN 48	0.01	-					
		2360702	SEC Accum Defd SIT - FIN 48	99,070.00	99,070.00	98,929.00	99,196.00	99,395.00	99,587.00	99,768.00
		2360801	Federal Income Tax - IRS Audit	185,585.25	(0.00)					
		2360901	Accum Defd FIT- IRS Audit	-	-					
	2360 Total			**(65,004,770.47)**	**(70,923,178.08)**	**(73,352,170.00)**	**(75,114,262.00)**	**(62,860,933.00)**	**(58,395,999.00)**	**(30,786,048.00)**
2370	**Interest Accrued**	2370002	Interest Accrued-Inst Pur Con	(428,000.00)	(71,333.33)	(80,531.00)	(77,042.00)	(54,332.00)	(71,524.00)	(88,581.00)
		2370005	Interest Accrd-Other LT Debt	(396,075.56)	(87,639.78)	(98,941.00)	(94,653.00)	(66,751.00)	(87,874.00)	(108,830.00)

Southerwestern Electric Power Company
Trial Balance - Balance Sheet
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by fiscal or calendar years. Also, provide

FERC	FERC Title	Account	Description	Balance 6/30/18	Balance 7/31/18	Forecasted Balance 8/31/18	Balance 9/30/18	Balance 10/31/18	Balance 11/30/18	Balance 12/31/18
		2370006	Interest Accrd-Sen Unsec Notes	(36,257,224.89)	(31,789,516.51)	(35,888,637.00)	(34,333,364.00)	(24,212,714.00)	(31,874,600.00)	(39,475,688.00)
		2370007	Interest Accrd-Customer Depsts	(835,300.91)	(979,956.75)	(1,106,318.00)	(1,058,374.00)	(746,391.00)	(982,580.00)	(1,216,894.00)
		2370018	Accrued Margin Interest	0.00	-	-	-	-	-	-
		2370025	Interest Over Recover - AR							
		2370348	Acrd Int. - SIT Reserve - LT	(88,336.00)	(88,336.00)	(99,727.00)	(95,405.00)	(67,282.00)	(88,572.00)	(109,694.00)
		2370448	Acrd Int. - SIT Reserve - ST	(20,788.00)	(20,788.00)	(23,469.00)	(22,451.00)	(15,833.00)	(20,844.00)	(25,814.00)
	2370 Total			**(38,025,725.36)**	**(33,037,570.37)**	**(37,297,623.00)**	**(35,681,289.00)**	**(25,163,303.00)**	**(33,125,994.00)**	**(41,025,501.00)**
2380	**Dividends Declared**	2380003	Div Decl - Common Stock-Affil	-	-	-	-	-	-	-
	2380 Total			**-**	**-**	**-**	**-**	**-**	**-**	**-**
2410	**Tax Collections Payable**	2410002	State Income Tax Withheld	(175,895.74)	(182,911.45)	(182,911.00)	(182,911.00)	(182,911.00)	(182,911.00)	(182,911.00)
		2410003	Local Income Tax Withheld	-	(0.00)	-	-	-	-	-
		2410004	State Sales Tax Collected	(3,740,935.95)	(4,957,391.48)	(4,957,391.00)	(4,957,391.00)	(4,957,391.00)	(4,957,391.00)	(4,957,391.00)
		2410005	FICA Tax Withheld	-	-	-	-	-	-	-
		2410008	Franchise Fee Collected	(3,790,394.11)	(1,899,362.30)	(1,899,362.00)	(1,899,362.00)	(1,899,362.00)	(1,899,362.00)	(1,899,362.00)
	2410 Total			**(7,707,225.80)**	**(7,039,665.23)**	**(7,039,664.00)**	**(7,039,664.00)**	**(7,039,664.00)**	**(7,039,664.00)**	**(7,039,664.00)**
2420	**Misc Current & Accrued Liab**	2420000	Misc Current & Accrued Liab	(18,069.00)	(18,069.00)	(18,149.00)	(18,230.00)	(18,310.00)	(18,390.00)	(18,471.00)
		2420002	P/R Ded - Medical Insurance	(357,498.75)	(357,066.68)	(358,655.00)	(360,243.00)	(361,831.00)	(363,419.00)	(365,007.00)
		2420003	P/R Ded - Dental Insurance	(43,505.22)	(43,273.57)	(43,466.00)	(43,659.00)	(43,851.00)	(44,043.00)	(44,236.00)
		2420007	P/R Ded - Savings Plan	-	-	-	-	-	-	-
		2420010	P/R Ded - Dependent Life Ins		(2.70)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)
		2420013	P/R Ded - LTD Ins Premiums	(5,166.41)	(5,149.19)	(5,172.00)	(5,195.00)	(5,218.00)	(5,241.00)	(5,264.00)
		2420016	P/R Ded-Crt Ordr/Grnshmt/Tx Lv		(10.00)	(10.00)	(10.00)	(10.00)	(10.00)	(10.00)
		2420017	P/R Ded - AD&D and OAD&D Ins		(11.83)	(12.00)	(12.00)	(12.00)	(12.00)	(12.00)
		2420018	P/R Ded-Reg&Spec Life Ins Prem		(23.28)	(23.00)	(23.00)	(24.00)	(24.00)	(24.00)
		2420020	Vacation Pay - This Year	(8,342,193.98)	(7,279,059.11)	(7,311,435.00)	(7,343,810.00)	(7,376,186.00)	(7,408,562.00)	(7,440,937.00)
		2420021	Vacation Pay - Next Year	(4,964,924.64)	(5,719,632.86)	(5,745,073.00)	(5,770,512.00)	(5,795,952.00)	(5,821,391.00)	(5,846,831.00)
		2420027	FAS 112 CURRENT LIAB	(1,510,148.81)	(1,510,148.81)	(1,516,866.00)	(1,523,582.00)	(1,530,299.00)	(1,537,016.00)	(1,543,733.00)
		2420028	ESP - Employer Contrib Accrued	-	-	-	-	-	-	-
		2420046	FAS 158 SERP Payable - Current	(150,521.00)	(150,521.00)	(151,190.00)	(151,860.00)	(152,529.00)	(153,199.00)	(153,868.00)
		2420051	Non-Productive Payroll	(426,208.96)	(462,130.08)	(464,186.00)	(466,241.00)	(468,296.00)	(470,352.00)	(472,407.00)
		2420053	Perf Share Incentive Plan	(1,161,980.87)	(1,184,550.79)	(1,189,819.00)	(1,195,088.00)	(1,200,357.00)	(1,205,625.00)	(1,210,894.00)
		2420059	MINE CLOSING COSTS - FERC	(0.00)	(0.00)	-	-	-	-	-
		2420071	P/R Ded - Vision Plan	(17,256.65)	(17,193.06)	(17,270.00)	(17,346.00)	(17,422.00)	(17,499.00)	(17,575.00)
		2420072	P/R - Payroll Adjustment	(3,145.07)	(2,419.88)	(2,431.00)	(2,441.00)	(2,452.00)	(2,463.00)	(2,474.00)
		2420076	P/R Savings Plan - Incentive	(235,482.62)	(279,871.79)	(281,117.00)	(282,361.00)	(283,606.00)	(284,851.00)	(286,096.00)
		2420081	Environmntl Remediation Accrua	(26,136.75)	(26,136.75)	(26,253.00)	(26,369.00)	(26,486.00)	(26,602.00)	(26,718.00)
		2420083	Active Med and Dental IBNR	-	-	-	-	-	-	-
		2420504	Accrued Lease Expense	(173,838.97)	(360,827.90)	(362,433.00)	(364,038.00)	(365,643.00)	(367,247.00)	(368,852.00)
		2420511	Control Cash Disburse Account	(3,992,714.80)	(5,772,907.26)	(5,798,584.00)	(5,824,260.00)	(5,849,937.00)	(5,875,614.00)	(5,901,290.00)
		2420512	Unclaimed Funds	(19,858.56)	(39,554.35)	(39,730.00)	(39,906.00)	(40,082.00)	(40,258.00)	(40,434.00)
		2420514	Revenue Refunds Accrued	(14,136,851.53)	(7,489,219.31)	(7,522,530.00)	(7,555,840.00)	(7,589,150.00)	(7,622,461.00)	(7,655,771.00)
		2420519	Provision for Unclaimed Funds							
		2420532	Adm Liab-Cur-S/Ins-W/C	(138,884.10)	(150,644.88)	(151,315.00)	(151,985.00)	(152,655.00)	(153,325.00)	(153,995.00)
		242053818	Federal Admin Fee	(36,705.00)	-	-	-	-	-	-
		2420558	Admitted Liab NC-Self/Ins-W/C	(628,505.73)	(534,691.64)	(537,070.00)	(539,448.00)	(541,826.00)	(544,204.00)	(546,583.00)
		242059216	Sales Use Tax - Leased Equip							
		242059217	Sales Use Tax - Leased Equip	-	-	-	-	-	-	-
		242059218	Sales Use Tax - Leased Equip	(1,791.19)	(3,859.99)	(3,877.00)	(3,894.00)	(3,911.00)	(3,929.00)	(3,946.00)
		2420618	Accrued Payroll	(4,611,855.51)	(5,492,496.72)	(5,516,926.00)	(5,541,356.00)	(5,565,785.00)	(5,590,214.00)	(5,614,644.00)
		2420623	Distr, Cust Ops & Reg Svcs ICP	(2,835,973.89)	(3,376,428.51)	(3,391,446.00)	(3,406,464.00)	(3,421,481.00)	(3,436,499.00)	(3,451,517.00)
		2420624	Corp & Shrd Srv Incentive Plan	(340,625.82)	(404,114.81)	(405,912.00)	(407,710.00)	(409,507.00)	(411,304.00)	(413,102.00)
		2420635	Generation Incentive Plan	(2,407,491.94)	(2,856,280.77)	(2,868,985.00)	(2,881,689.00)	(2,894,393.00)	(2,907,097.00)	(2,919,801.00)
		2420643	Accrued Audit Fees	(52,031.81)	(141,373.23)	(142,002.00)	(142,631.00)	(143,260.00)	(143,888.00)	(144,517.00)
		2420644	Reclamation Liability - Affil	(78,186,338.00)	(78,480,216.00)	(78,829,278.00)	(79,178,341.00)	(79,527,403.00)	(79,876,466.00)	(80,225,528.00)
		2420649	Reclamation Liability - Curr	(1,906.78)	(812.88)	(816.00)	(820.00)	(824.00)	(827.00)	(831.00)
		2420660	AEP Transmission ICP	(448,664.95)	(532,032.79)	(534,399.00)	(536,766.00)	(539,132.00)	(541,498.00)	(543,865.00)
		2420662	Accrued Railcar Lease Exp - ST	(12,687.29)	(12,687.29)	(12,744.00)	(12,800.00)	(12,857.00)	(12,913.00)	(12,969.00)
		2420663	Accrued railcar lease exp - LT	(94,614.72)	(93,146.38)	(93,561.00)	(93,975.00)	(94,389.00)	(94,804.00)	(95,218.00)
		2420665	Dollar Energy Assistance Pgm	(1,420.56)	(1,115.21)	(1,120.00)	(1,125.00)	(1,130.00)	(1,135.00)	(1,140.00)
		2420700	Quality of Service	(212,399.00)	(212,399.00)	(213,344.00)	(214,288.00)	(215,233.00)	(216,178.00)	(217,123.00)

Southerwestern Electric Power Company
Trial Balance - Balance Sheet
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by fiscal or calendar years. Also, provide

FERC	FERC Title	Account	Description	Balance 6/30/18	Balance 7/31/18	Forecasted Balance 8/31/18	Forecasted Balance 9/30/18	Forecasted Balance 10/31/18	Forecasted Balance 11/30/18	Forecasted Balance 12/31/18
	2420 Total			**(125,597,398.88)**	**(123,010,079.30)**	**(123,557,202.00)**	**(124,104,321.00)**	**(124,651,442.00)**	**(125,198,563.00)**	**(125,745,686.00)**
2430	**Oblig Under Cap Leases - Curr**	2430001	Oblig Under Cap Leases - Curr	(4,205,350.03)	(4,144,099.74)	(3,698,923.00)	(3,379,135.00)	(2,832,608.00)	(2,546,221.00)	(6,203,813.00)
		2430003	Accrued Cur Lease Oblig	(26,954.63)	(24,909.28)	(22,233.00)	(20,311.00)	(17,026.00)	(15,305.00)	(37,290.00)
	2430 Total			**(4,232,304.66)**	**(4,169,009.02)**	**(3,721,156.00)**	**(3,399,446.00)**	**(2,849,634.00)**	**(2,561,526.00)**	**(6,241,103.00)**
2440	**Curr. Unreal Losses - NonAffil**	2440001	Curr. Unreal Losses - NonAffil	(29,804.90)	(212,268.12)	(212,268.00)	(212,268.00)	(212,268.00)	(212,268.00)	(212,268.00)
		2440002	LT Unreal Losses - Non Affil	(2,267,820.57)	(2,580,152.96)	(2,580,153.00)	(2,580,153.00)	(2,580,153.00)	(2,580,153.00)	(2,580,153.00)
	2440 Total			**(2,297,625.47)**	**(2,792,421.08)**	**(2,792,421.00)**	**(2,792,421.00)**	**(2,792,421.00)**	**(2,792,421.00)**	**(2,792,421.00)**
2530	**Other Deferred Credits**	2530000	Other Deferred Credits	(6,202,269.34)	(6,075,647.82)	(6,096,080.00)	(6,116,512.00)	(6,136,944.00)	(6,157,376.00)	(6,177,808.00)
		2530022	Customer Advance Receipts	(4,368,348.30)	(3,415,039.62)	(3,426,524.00)	(3,438,009.00)	(3,449,493.00)	(3,460,978.00)	(3,472,462.00)
		2530050	Deferred Rev -Pole Attachments	(109,190.79)	(2,182,849.08)	(2,190,190.00)	(2,197,531.00)	(2,204,871.00)	(2,212,212.00)	(2,219,553.00)
		2530067	IPP - System Upgrade Credits	(6,916,768.12)	(6,943,788.32)	(6,967,140.00)	(6,990,491.00)	(7,013,843.00)	(7,037,194.00)	(7,060,546.00)
		2530101	MACSS Unidentified EDI Cash	(2,738.32)	(2,434.72)	(2,443.00)	(2,451.00)	(2,459.00)	(2,467.00)	(2,476.00)
		2530104	Railroad Cars Subleased-Rev	-	141.35	142.00	142.00	143.00	143.00	144.00
		2530112	Other Deferred Credits-Curr	(173,161.12)	(160,777.46)	(161,318.00)	(161,859.00)	(162,400.00)	(162,940.00)	(163,481.00)
		2530120	Environ Remediation LT	(143,956.85)	(143,956.85)	(142,456.00)	(140,955.00)	(139,454.00)	(137,953.00)	(136,452.00)
		2530124	Contr In Aid of Constr Advance	(338,114.78)	(318,300.24)	(314,981.00)	(311,662.00)	(308,344.00)	(305,025.00)	(301,706.00)
		2530139	IPP - Aff. Sys Upgrade Credits	(0.00)	(0.00)	-	-	-	-	-
		2530181	Oxbow Buy In	(2,814,125.43)	(2,807,662.04)	(2,817,104.00)	(2,826,546.00)	(2,835,988.00)	(2,845,430.00)	(2,854,872.00)
		2530185	O\U Accounting of ExpensesT	(29,613.81)	12,042.68	12,083.00	12,124.00	12,164.00	12,205.00	12,245.00
		2530188	Long Term Assoc AP	(3,653,778.00)	(3,654,588.00)	(3,666,878.00)	(3,679,168.00)	(3,691,458.00)	(3,703,749.00)	(3,716,039.00)
		2530190	QUAL OF SVC PENALTIES - LT	-	-	-	-	-	-	-
	2530 Total			**(24,752,064.86)**	**(25,692,860.12)**	**(25,772,889.00)**	**(25,852,918.00)**	**(25,932,947.00)**	**(26,012,976.00)**	**(26,093,006.00)**
2540	**Other Regulatory Liabilities**	2540047	Unreal Gain on Fwd Commitments	(298,975.00)	(195,847.00)	(193,805.00)	(191,763.00)	(189,721.00)	(187,679.00)	(185,637.00)
		2540050	Def Rev Selling Price Variance	-	0.00	-	-	-	-	-
		2540052	EXCESS EARNINGS	(2,579,476.00)	(2,573,476.00)	(2,546,643.00)	(2,519,809.00)	(2,492,976.00)	(2,466,143.00)	(2,439,310.00)
		2540058	Dolet Hills Mining Buy-Out	(272,905.57)	(272,905.57)	(270,060.00)	(267,214.00)	(264,369.00)	(261,523.00)	(258,678.00)
		2540090	Over Recovered Fuel Cost - TX	(9,135,863.37)	(12,424,402.02)	-	-	-	-	-
		2540094	Over Recovered Fuel Cost - LA	(2,255,796.60)	(5,230,601.51)	-	-	-	-	-
		2540118	Energy Efficiency O/U Recovery	(353,979.11)	(594,898.25)	(588,695.00)	(582,492.00)	(576,289.00)	(570,087.00)	(563,884.00)
		2540137	Over Recovered EAC - LA	-	-	-	-	-	-	-
		2540139	Refundable Construction Int-LA							
		2540174	JLStall GR Rider Over Recovery	(2,156,539.34)	(2,462,264.79)	(2,436,591.00)	(2,410,917.00)	(2,385,244.00)	(2,359,570.00)	(2,333,896.00)
		2540184	Texas Vegetation Management	(3,224,407.60)	(2,859,454.09)	(2,829,639.00)	(2,799,824.00)	(2,770,009.00)	(2,740,194.00)	(2,710,379.00)
		2540191	LA SQIP Veg Mgmt O/U Recovery	(2,885,263.88)	(3,142,610.47)	(3,109,843.00)	(3,077,075.00)	(3,044,308.00)	(3,011,540.00)	(2,978,773.00)
	2540 Total			**(23,163,206.47)**	**(29,756,459.70)**	**(11,975,276.00)**	**(11,849,094.00)**	**(11,722,916.00)**	**(11,596,736.00)**	**(11,470,557.00)**
2543	**SFAS 109 Flow Thru Defd FIT**	2543001	SFAS109 Flow Thru Def FIT Liab	(1,380,987.91)	(1,349,483.13)	(1,346,139.00)	(1,341,698.00)	(1,337,426.00)	(1,333,153.00)	(1,328,881.00)
	2543 Total			**(1,380,987.91)**	**(1,349,483.13)**	**(1,346,139.00)**	**(1,341,698.00)**	**(1,337,426.00)**	**(1,333,153.00)**	**(1,328,881.00)**
2544	**SFAS 109 Exces Deferred FIT**	2544001	SFAS 109 Exces Deferred FIT	(707,819,522.06)	(706,704,599.26)	(704,953,178.00)	(702,627,873.00)	(700,390,441.00)	(698,153,010.00)	(695,915,578.00)
		2544009	OCI - Excess DFIT	-	-					
	2544 Total			**(707,819,522.06)**	**(706,704,599.26)**	**(704,953,178.00)**	**(702,627,873.00)**	**(700,390,441.00)**	**(698,153,010.00)**	**(695,915,578.00)**
2550	**Accum Def Invest Tax Credit**	2550001	Accum Deferred ITC - Federal	(5,195,145.00)	(5,076,627.00)	(4,993,673.00)	(4,910,720.00)	(4,827,766.00)	(4,744,813.00)	(4,661,859.00)
	2550 Total			**(5,195,145.00)**	**(5,076,627.00)**	**(4,993,673.00)**	**(4,910,720.00)**	**(4,827,766.00)**	**(4,744,813.00)**	**(4,661,859.00)**
2570	**Unamt Gain on Reacquired Debt**	2570001	Unamort Gn Reacq Debt - FMB	(14,454.83)	(13,528.87)	(13,529.00)	(13,529.00)	(13,529.00)	(13,529.00)	(13,529.00)
	2570 Total			**(14,454.83)**	**(13,528.87)**	**(13,529.00)**	**(13,529.00)**	**(13,529.00)**	**(13,529.00)**	**(13,529.00)**
2811	**Acc Def Inc Tax-Acc Amort Prop**	2811001	Acc Dfd FIT - Accel Amort Prop	(67,751,661.95)	(67,837,971.95)	(67,741,162.00)	(67,924,051.00)	(68,060,250.00)	(68,192,004.00)	(68,316,218.00)
	2811 Total			**(67,751,661.95)**	**(67,837,971.95)**	**(67,741,162.00)**	**(67,924,051.00)**	**(68,060,250.00)**	**(68,192,004.00)**	**(68,316,218.00)**
2814	**Acc Def Inc Tax-Acc Amort Prop**	2814001	Acc Dfd FIT - FAS 109 Excess	26,962,712.00	26,962,712.00	26,924,234.00	26,996,925.00	27,051,058.00	27,103,425.00	27,152,794.00
	2814 Total			**26,962,712.00**	**26,962,712.00**	**26,924,234.00**	**26,996,925.00**	**27,051,058.00**	**27,103,425.00**	**27,152,794.00**
2821	**Accum Defd FIT - Utility Prop**	2821001	Accum Defd FIT - Utility Prop	(1,372,081,122.30)	(1,372,305,079.12)	(1,370,346,704.00)	(1,374,046,386.00)	(1,376,801,573.00)	(1,379,466,842.00)	(1,381,979,593.00)
	2821 Total			**(1,372,081,122.30)**	**(1,372,305,079.12)**	**(1,370,346,704.00)**	**(1,374,046,386.00)**	**(1,376,801,573.00)**	**(1,379,466,842.00)**	**(1,381,979,593.00)**
2823	**Accum Defd FIT - Other Prop**	2823001	Acc Dfrd FIT FAS 109 Flow Thru	(55,131,578.46)	(55,054,998.06)	(54,976,431.00)	(55,124,857.00)	(55,235,391.00)	(55,342,318.00)	(55,443,126.00)

Southerwestern Electric Power Company
Trial Balance - Balance Sheet
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by fiscal or calendar years. Also, provide

FERC	FERC Title	Account	Description	Balance 6/30/18	Balance 7/31/18	Forecasted Balance 8/31/18	Forecasted Balance 9/30/18	Forecasted Balance 10/31/18	Forecasted Balance 11/30/18	Forecasted Balance 12/31/18
	2823 Total			**(55,131,578.46)**	**(55,054,998.06)**	**(54,976,431.00)**	**(55,124,857.00)**	**(55,235,391.00)**	**(55,342,318.00)**	**(55,443,126.00)**
2824	**Accum Defd FIT - Other Prop**	2824001	Acc Dfrd FIT - SFAS 109 Excess	541,103,696.84	540,222,907.84	539,451,972.00	540,908,392.00	541,993,002.00	543,042,214.00	544,031,386.00
	2824 Total			**541,103,696.84**	**540,222,907.84**	**539,451,972.00**	**540,908,392.00**	**541,993,002.00**	**543,042,214.00**	**544,031,386.00**
2831	**Accum Deferred FIT - Other**	2831001	Accum Deferred FIT - Other	(33,235,438.63)	(32,930,400.32)	(32,883,406.00)	(32,972,185.00)	(33,038,300.00)	(33,102,257.00)	(33,162,554.00)
		2831002	Accum Deferred SIT - Other							
	2831 Total			**(33,235,438.63)**	**(32,930,400.32)**	**(32,883,406.00)**	**(32,972,185.00)**	**(33,038,300.00)**	**(33,102,257.00)**	**(33,162,554.00)**
2832	**Accum Dfrd FIT - Oth Inc & Ded**	2832001	Accum Dfrd FIT - Oth Inc & Ded							
	2832 Total			**-**	**-**	**-**	**-**	**-**	**-**	**-**
										(1,347,372.00)
2833	**Acc Dfd FIT FAS 109 Flow Thru**	2833001	Acc Dfd FIT FAS 109 Flow Thru	(54,714,806.17)	(54,730,848.10)	(54,652,743.00)	(54,800,296.00)	(54,910,179.00)	(55,016,477.00)	(55,116,691.00)
		2833002	Acc Dfrd SIT FAS 109 Flow Thru	(190,948,243.00)	(191,121,231.00)	(190,848,488.00)	(191,363,743.00)	(191,747,459.00)	(192,118,651.00)	(192,468,603.00)
	2833 Total			**(245,663,049.17)**	**(245,852,079.10)**	**(245,501,231.00)**	**(246,164,039.00)**	**(246,657,638.00)**	**(247,135,128.00)**	**(247,585,294.00)**
2834	**Acc Defd FIT - SFAS 109 Excess**	2834001	Acc Defd FIT - SFAS 109 Excess	(8,888,986.41)	(8,888,986.41)	(8,876,301.00)	(8,900,266.00)	(8,918,112.00)	(8,935,376.00)	(8,951,652.00)
	2834 Total			**(8,888,986.41)**	**(8,888,986.41)**	**(8,876,301.00)**	**(8,900,266.00)**	**(8,918,112.00)**	**(8,935,376.00)**	**(8,951,652.00)**
Total	Total			-	0.00	-	-	-	-	-
			Assets	**7,517,321,329.38**	**7,530,576,049.10**	**7,522,232,504.00**	**8,026,325,314.00**	**7,606,432,981.00**	**7,600,231,852.00**	**7,600,799,190.00**
			Liabilities	**(7,517,321,329.38)**	**(7,530,576,049.09)**	**(7,522,232,504.00)**	**(8,026,325,314.00)**	**(7,606,432,981.00)**	**(7,600,231,852.00)**	**(7,600,799,190.00)**

Southerwestern Electric Power Company
Plant In Service
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

Line No.	Category	Account	Location	Balance 12/31/16	Balance 12/31/17	Balance 1/31/18	Balance 2/28/18	Historic Balances Balance 3/31/18	Balance 4/30/18	Balance 5/31/18	Balance 6/30/18
	Generation Plant									(Note 2)	
	Arsenal Hill										
1		31030 - Land - Oil/Gas	Arsenal Hill Generating Plant	370,798.41	370,798.41	370,798.41	370,798.41	370,798.41	370,798.41	370,798.41	370,798.41
2		31130 - Struct, Improvemnts-Oil/Gas	Arsenal Hill Generating Plant	5,546,425.23	5,588,727.82	5,798,815.00	5,798,815.00	5,798,815.00	5,798,815.00	5,798,815.00	5,798,815.00
3		31230 - Boiler Plant Equip-Oil/Gas	Arsenal Hill Generating Plant	6,727,644.97	6,801,741.84	6,801,933.87	6,802,035.84	6,823,823.36	6,858,410.35	6,859,359.13	6,859,386.53
4		31430 - Turbogenator Units-Oil/Gas	Arsenal Hill Generating Plant	4,724,049.06	4,779,169.21	4,779,169.21	4,779,907.55	4,779,907.55	4,779,907.55	4,779,907.55	4,779,907.55
5		31530 - Accssry Elect Equip-Oil/Gas	Arsenal Hill Generating Plant	1,115,814.59	1,204,051.69	1,208,686.26	1,210,669.00	1,211,017.78	1,210,370.51	1,210,370.51	1,210,370.51
6		31630 - Misc Pwr Plt Equip-Oil/Gas	Arsenal Hill Generating Plant	6,982,540.97	7,029,210.27	7,030,492.78	7,030,493.46	7,031,441.46	7,031,973.51	7,031,946.12	7,033,250.60
7		31730 - ARO Steam Prod Plnt Oil/Gas	Arsenal Hill Generating Plant	507,714.26	507,714.26	507,714.26	507,714.26	507,714.26	507,714.26	507,714.26	507,714.26
8			**Total**	**25,974,987.49**	**26,281,413.50**	**26,497,609.79**	**26,500,433.52**	**26,523,517.82**	**26,557,989.59**	**26,558,910.98**	**26,560,242.86**
	Dolet Hills										
9		31000 - Land - Coal Fired	Dolet Hills Generating Plant	1,510,614.56	1,510,614.56	1,510,614.56	1,510,614.56	1,510,614.56	1,510,614.56	1,510,614.56	1,510,614.56
10		31100 - Structures, Improvemnt-Coal	Dolet Hills Generating Plant	55,632,386.33	56,035,005.60	56,051,819.35	56,049,776.71	56,080,127.65	56,079,514.25	56,208,492.25	56,186,888.89
11		31200 - Boiler Plant Equip-Coal	Dolet Hills Generating Plant	209,585,757.29	215,685,915.67	215,682,297.38	215,681,894.53	216,966,350.47	216,966,558.37	217,321,619.71	219,834,536.01
12		31400 - Turbogenerator Units-Coal	Dolet Hills Generating Plant	39,044,256.80	39,618,875.47	39,618,875.47	39,618,875.47	39,644,989.03	39,644,196.80	39,644,002.60	39,652,480.44
13		31500 - Accessory Elect Equip-Coal	Dolet Hills Generating Plant	11,062,090.40	12,050,250.67	12,034,006.19	12,027,691.20	12,041,569.51	12,041,188.34	12,041,188.34	12,041,188.34
14		31600 - Misc Pwr Plant Equip-Coal	Dolet Hills Generating Plant	15,483,942.85	15,660,497.02	15,660,497.02	15,660,497.02	16,011,961.27	16,009,692.19	16,042,544.86	16,107,051.30
15		31700 - ARO Steam Production Plant	Dolet Hills Generating Plant	2,529,657.27	2,529,657.27	2,529,657.27	2,529,657.27	2,529,657.27	2,529,657.27	2,529,657.27	1,230,657.52
16			**Total**	**334,848,705.50**	**343,090,816.26**	**343,087,767.24**	**343,079,006.76**	**344,785,269.76**	**344,781,421.78**	**345,298,119.59**	**346,563,417.06**
	Flint Creek										
17		31000 - Land - Coal Fired	Flint Creek Generating Plant	3,364,925.23	3,364,925.23	3,364,925.23	3,364,925.23	3,364,925.23	3,364,925.23	3,364,925.23	3,364,925.23
18		31100 - Structures, Improvemnt-Coal	Flint Creek Generating Plant	25,739,190.83	26,679,800.78	26,679,800.78	26,679,941.93	26,679,941.93	26,679,941.93	26,700,391.71	26,700,427.19
19		31200 - Boiler Plant Equip-Coal	Flint Creek Generating Plant	288,032,498.83	288,828,079.27	288,829,687.04	288,817,104.93	288,822,927.98	288,823,303.54	294,870,725.71	295,300,557.20
20		31211 - Coal Transportation Equip	Flint Creek Generating Plant	6,782,998.52	6,725,198.35	6,725,198.35	6,725,198.35	6,725,198.35	6,725,198.35	6,725,198.35	6,725,198.35
21		31400 - Turbogenerator Units-Coal	Flint Creek Generating Plant	14,604,001.34	14,673,888.54	14,673,888.54	14,673,888.54	14,673,888.54	14,673,888.54	14,673,888.54	14,673,888.54
22		31500 - Accessory Elect Equip-Coal	Flint Creek Generating Plant	8,188,997.28	8,784,164.99	8,784,164.99	8,784,164.99	8,784,164.99	8,785,717.49	8,784,987.01	8,784,987.01
23		31600 - Misc Pwr Plant Equip-Coal	Flint Creek Generating Plant	5,988,021.97	5,996,085.27	5,996,085.27	6,027,554.61	6,027,054.71	6,027,067.96	6,052,115.70	6,079,705.57
24		31700 - ARO Steam Production Plant	Flint Creek Generating Plant	9,719,253.01	9,719,253.01	9,719,253.01	9,719,253.01	9,719,253.01	9,719,253.01	9,719,253.01	9,719,253.01
25			**Total**	**362,419,887.01**	**364,771,395.44**	**364,773,003.21**	**364,792,031.59**	**364,797,354.74**	**364,799,296.05**	**370,891,485.26**	**371,348,942.10**
	Knox Lee										
26		31030 - Land - Oil/Gas	Knox Lee Generating Plant	102,781.04	102,781.04	102,781.04	102,781.04	102,781.04	102,781.04	102,781.04	102,781.04
27		31130 - Struct, Improvemnts-Oil/Gas	Knox Lee Generating Plant	7,893,414.20	8,070,905.00	8,311,779.13	8,322,788.72	8,323,706.63	8,323,697.13	8,323,697.13	8,323,697.13
28		31230 - Boiler Plant Equip-Oil/Gas	Knox Lee Generating Plant	34,743,380.33	35,208,827.33	35,208,827.33	35,126,300.08	35,126,300.08	35,326,138.78	35,345,615.95	35,451,263.49
29		31430 - Turbogenator Units-Oil/Gas	Knox Lee Generating Plant	19,852,734.11	21,481,665.95	21,770,025.49	21,770,091.27	21,770,091.27	21,776,796.46	21,776,746.89	21,776,746.89
30		31530 - Accssry Elect Equip-Oil/Gas	Knox Lee Generating Plant	3,847,113.52	4,011,903.73	4,014,885.46	4,015,029.99	4,015,054.98	4,015,054.98	4,015,733.30	4,057,229.73
31		31630 - Misc Pwr Plt Equip-Oil/Gas	Knox Lee Generating Plant	1,833,817.72	1,868,019.36	1,868,018.97	1,868,018.97	1,868,018.97	1,868,018.97	1,868,018.97	1,876,352.79
32		31730 - ARO Steam Prod Plnt Oil/Gas	Knox Lee Generating Plant	2,036,607.78	2,036,607.78	2,036,607.78	2,036,607.78	2,036,607.78	2,036,607.78	2,036,607.78	2,036,607.78
33			**Total**	**70,309,848.70**	**72,780,710.19**	**73,312,925.20**	**73,241,617.85**	**73,242,560.75**	**73,449,095.14**	**73,469,201.06**	**73,624,678.85**
	Lieberman										
34		31030 - Land - Oil/Gas	Lieberman Generating Plant	24,026.38	24,026.38	24,026.38	24,026.38	24,026.38	24,026.38	24,026.38	24,026.38
35		31130 - Struct, Improvemnts-Oil/Gas	Lieberman Generating Plant	3,804,153.57	3,829,290.16	3,829,290.16	3,829,290.16	3,829,290.16	3,829,290.16	3,829,290.16	3,829,290.16
36		31230 - Boiler Plant Equip-Oil/Gas	Lieberman Generating Plant	17,263,722.59	18,397,833.91	18,397,833.91	18,397,833.91	18,397,833.91	18,397,833.91	18,397,833.91	18,397,833.91
37		31430 - Turbogenator Units-Oil/Gas	Lieberman Generating Plant	10,933,755.43	11,678,559.77	11,678,559.77	11,678,559.77	11,678,559.77	11,678,559.77	11,678,559.77	11,678,559.77
38		31530 - Accssry Elect Equip-Oil/Gas	Lieberman Generating Plant	3,424,110.85	3,431,323.47	3,431,323.47	3,431,323.47	3,431,323.47	3,431,323.47	3,431,323.47	3,431,323.47
39		31630 - Misc Pwr Plt Equip-Oil/Gas	Lieberman Generating Plant	2,082,777.12	2,137,094.75	2,137,094.75	2,137,094.75	2,137,094.75	2,137,094.75	2,137,094.75	2,137,094.75
40		31730 - ARO Steam Prod Plnt Oil/Gas	Lieberman Generating Plant	1,263,344.24	1,263,344.24	1,263,344.24	1,263,344.24	1,263,344.24	1,263,344.24	1,263,344.24	1,263,344.24
41			**Total**	**38,795,890.18**	**40,761,472.68**	**40,761,472.68**	**40,761,472.68**	**40,761,472.68**	**40,761,472.68**	**40,761,472.68**	**40,761,472.68**

Southerwestern Electric Power Company
Plant In Service
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

Line No.	Category	Account	Location	Balance 12/31/16	Balance 12/31/17	Historic Balances Balance 1/31/18	Balance 2/28/18	Balance 3/31/18	Balance 4/30/18	Balance 5/31/18	Balance 6/30/18
	Lone Star										
42		31030 - Land - Oil/Gas	Lone Star Generating Plant	58,486.72	58,486.72	58,486.72	58,486.72	58,486.72	58,486.72	58,486.72	58,486.72
43		31130 - Struct, Improvemnts-Oil/Gas	Lone Star Generating Plant	929,624.02	934,757.43	934,757.43	934,757.43	934,757.43	934,757.43	934,757.43	934,757.43
44		31230 - Boiler Plant Equip-Oil/Gas	Lone Star Generating Plant	4,149,710.32	4,148,919.64	4,148,919.64	4,148,919.64	4,148,919.64	4,148,919.64	4,148,919.64	4,148,919.64
45		31430 - Turbogenator Units-Oil/Gas	Lone Star Generating Plant	2,512,253.07	2,586,137.30	2,586,137.30	2,586,137.30	2,586,137.30	2,586,137.30	2,586,137.30	2,586,137.30
46		31530 - Accssry Elect Equip-Oil/Gas	Lone Star Generating Plant	858,440.74	876,655.87	876,655.87	876,655.87	876,655.87	876,655.87	876,655.87	876,655.87
47		31630 - Misc Pwr Plt Equip-Oil/Gas	Lone Star Generating Plant	202,780.15	201,388.92	201,388.92	201,388.92	201,388.92	201,388.92	201,388.92	201,388.92
48		31730 - ARO Steam Prod Plnt Oil/Gas	Lone Star Generating Plant	123,591.52	123,591.52	123,591.52	123,591.52	123,591.52	123,591.52	123,591.52	123,591.52
49			**Total**	**8,834,886.54**	**8,929,937.40**	**8,929,937.40**	**8,929,937.40**	**8,929,937.40**	**8,929,937.40**	**8,929,937.40**	**8,929,937.40**
	Mattison										
50		34000 - Land	Mattison Generating Plant	1,451,852.12	1,451,852.12	1,451,852.12	1,451,852.12	1,451,852.12	1,451,852.12	1,451,852.12	1,451,852.12
51		34100 - Structures & Improvmnts	Mattison Generating Plant	34,884,390.81	34,886,948.05	34,886,948.05	34,909,114.30	34,909,147.64	34,909,147.64	34,912,734.09	34,912,751.16
52		34400 - Generators	Mattison Generating Plant	84,006,951.77	84,006,951.77	84,008,451.94	84,008,654.87	84,008,692.35	84,008,692.35	84,008,692.35	84,008,692.35
53		34500 - Accessory Electric Equip	Mattison Generating Plant	8,744,937.10	8,926,714.47	8,924,881.20	8,994,154.02	8,995,110.85	8,994,746.26	8,994,738.42	8,994,738.42
54		34600 - Misc Power Plant Equip	Mattison Generating Plant	751,712.61	779,474.94	779,474.94	779,474.94	779,474.94	781,560.42	781,560.42	781,560.42
55			**Total**	**129,839,844.41**	**130,051,941.35**	**130,051,608.25**	**130,143,250.25**	**130,144,277.90**	**130,145,998.79**	**130,149,577.40**	**130,149,594.47**
	Pirkey										
56		31000 - Land - Coal Fired	Pirkey Generating Plant	5,843,028.51	5,843,028.51	5,843,028.51	5,843,028.51	5,843,028.51	5,843,028.51	5,843,028.51	5,843,028.51
57		31100 - Structures, Improvemnt-Coal	Pirkey Generating Plant	108,246,135.21	108,542,724.63	108,542,724.63	108,542,724.63	108,542,724.63	108,542,724.63	108,542,724.63	108,542,724.63
58		31200 - Boiler Plant Equip-Coal	Pirkey Generating Plant	365,171,817.57	367,668,660.39	367,660,817.80	367,674,837.92	367,674,743.58	367,677,355.46	367,733,516.04	367,934,175.23
59		31400 - Turbogenerator Units-Coal	Pirkey Generating Plant	50,932,031.00	50,945,628.34	50,945,628.34	50,945,628.34	50,945,628.34	50,945,628.34	50,945,628.34	50,945,628.34
60		31500 - Accessory Elect Equip-Coal	Pirkey Generating Plant	17,641,698.36	17,764,351.11	17,764,351.11	17,764,351.11	17,764,351.11	17,788,802.57	17,789,940.05	18,049,397.31
61		31600 - Misc Pwr Plant Equip-Coal	Pirkey Generating Plant	17,933,258.39	18,374,251.85	18,374,251.85	18,374,251.85	18,375,919.87	18,417,560.13	18,434,179.41	18,446,715.56
62		31700 - ARO Steam Production Plant	Pirkey Generating Plant	20,646,275.80	20,646,275.80	20,646,275.80	20,646,275.80	20,646,275.80	20,646,275.80	20,646,275.80	20,646,275.80
63			**Total**	**586,414,244.84**	**589,784,920.63**	**589,777,078.04**	**589,791,098.16**	**589,792,671.84**	**589,861,375.44**	**589,935,292.78**	**590,407,945.38**
	Stall										
64		31130 - Struct, Improvemnts-Oil/Gas	Arsenal Hill Generating Plant	53,275,761.93	53,277,155.37	53,277,155.64	53,278,426.64	53,279,263.68	53,279,773.32	53,270,252.78	53,282,031.70
65		31230 - Boiler Plant Equip-Oil/Gas	Arsenal Hill Generating Plant	86,992,558.71	87,269,440.75	87,274,028.50	87,248,085.38	87,181,687.56	87,178,552.32	87,176,681.54	87,182,407.25
66		31430 - Turbogenator Units-Oil/Gas	Arsenal Hill Generating Plant	166,691,706.06	168,627,190.28	168,910,117.80	168,917,341.61	168,961,467.87	168,963,422.41	169,005,670.96	169,007,717.43
67		31530 - Accssry Elect Equip-Oil/Gas	Arsenal Hill Generating Plant	40,354,778.00	40,335,012.62	40,335,012.83	40,335,143.08	40,335,263.60	40,335,655.50	40,335,724.91	40,329,158.98
68		31630 - Misc Pwr Plt Equip-Oil/Gas	Arsenal Hill Generating Plant	84,668,937.92	84,690,322.67	84,690,323.30	84,690,597.55	84,690,851.33	84,694,540.92	84,694,887.43	84,695,259.83
69			**Total**	**431,983,742.62**	**434,199,121.69**	**434,486,638.07**	**434,469,594.26**	**434,448,534.04**	**434,451,944.47**	**434,483,217.62**	**434,496,575.19**
	Turk										
70		31000 - Land - Coal Fired	Turk Generating Plant	11,468,899.32	11,468,899.32	11,468,899.32	11,468,899.32	11,468,899.32	11,468,899.32	11,468,899.32	11,468,899.32
71		31010 - Land Rights - Coal Fired	Turk Generating Plant	1,886,717.17	1,886,717.17	1,886,717.17	1,886,717.17	1,886,717.17	1,886,717.17	1,886,717.17	1,886,717.17
72		31100 - Structures, Improvemnt-Coal	Turk Generating Plant	284,564,421.08	284,833,097.91	284,858,827.17	284,865,375.00	284,866,141.36	284,583,203.78	284,987,003.36	284,954,167.83
73		31200 - Boiler Plant Equip-Coal	Turk Generating Plant	983,457,322.67	984,356,056.04	984,359,050.36	984,376,646.26	984,383,376.83	984,384,897.90	984,393,176.90	986,341,112.84
74		31400 - Turbogenerator Units-Coal	Turk Generating Plant	232,539,373.96	232,599,491.86	232,599,491.86	232,599,491.86	232,599,491.86	232,599,491.86	232,599,491.86	232,599,491.86
75		31500 - Accessory Elect Equip-Coal	Turk Generating Plant	93,288,695.54	93,338,871.06	93,338,871.06	93,338,871.06	93,338,871.06	93,338,871.06	93,338,871.06	93,338,871.06
76		31600 - Misc Pwr Plant Equip-Coal	Turk Generating Plant	47,952,776.38	47,958,538.98	47,953,861.34	47,956,168.03	47,957,248.39	47,959,992.20	47,971,389.28	47,972,286.58
77		31700 - ARO Steam Production Plant	Turk Generating Plant	2,179,312.62	2,179,312.62	2,179,312.62	2,179,312.62	2,179,312.62	2,179,312.62	2,179,312.62	2,179,312.62
78			**Total**	**1,657,337,518.74**	**1,658,620,984.96**	**1,658,645,030.90**	**1,658,671,481.32**	**1,658,680,058.61**	**1,658,401,385.91**	**1,658,824,861.57**	**1,660,740,859.28**
	Welsh										
79		31000 - Land - Coal Fired	Welsh Generating Plant	1,895,473.50	1,895,473.50	1,895,473.50	1,895,473.50	1,895,473.50	1,895,473.50	1,895,473.50	1,895,473.50
80		31100 - Structures, Improvemnt-Coal	Welsh Generating Plant	75,282,031.10	76,094,694.15	76,132,018.11	76,132,026.62	71,893,112.31	71,896,694.28	71,942,408.55	71,942,647.72
81		31200 - Boiler Plant Equip-Coal	Welsh Generating Plant	511,703,314.86	576,471,406.22	576,416,509.88	576,434,161.65	576,451,682.34	576,593,569.65	576,598,120.30	576,813,289.56
82		31211 - Coal Transportation Equip	Welsh Generating Plant	10,797,602.33	10,624,201.80	10,624,201.80	10,624,201.80	10,567,148.51	10,567,148.51	10,567,148.51	10,567,148.51
83		31400 - Turbogenerator Units-Coal	Welsh Generating Plant	112,704,429.26	137,345,243.40	137,342,610.74	137,471,783.95	137,345,313.57	137,348,383.85	137,349,192.38	137,349,192.38
84		31500 - Accessory Elect Equip-Coal	Welsh Generating Plant	129,808,771.01	42,359,130.63	42,549,730.60	42,543,561.66	45,704,497.98	45,695,420.62	45,690,572.05	45,690,452.66
85		31600 - Misc Pwr Plant Equip-Coal	Welsh Generating Plant	20,706,098.94	20,908,619.71	20,914,336.27	21,192,041.64	21,197,779.26	21,197,779.26	21,197,775.20	21,199,494.87
86		31700 - ARO Steam Production Plant	Welsh Generating Plant	19,114,677.58	19,114,677.58	19,114,677.58	19,114,677.58	19,114,677.58	19,114,677.58	19,114,677.58	19,114,677.58
87			**Total**	**882,012,398.58**	**884,813,446.99**	**884,989,558.48**	**885,407,928.40**	**884,169,685.05**	**884,309,147.25**	**884,355,368.07**	**884,572,376.78**
	Wilkes										
88		31030 - Land - Oil/Gas	Wilkes Generating Plant	443,729.45	443,729.45	443,729.45	443,729.45	443,729.45	443,729.45	443,729.45	443,729.45
89		31130 - Struct, Improvemnts-Oil/Gas	Wilkes Generating Plant	7,585,357.92	7,775,584.04	7,775,584.04	7,775,584.04	7,775,584.04	7,775,584.04	7,775,584.04	7,853,337.72
90		31230 - Boiler Plant Equip-Oil/Gas	Wilkes Generating Plant	40,864,760.76	47,174,346.94	47,197,153.58	46,763,777.25	47,374,987.70	47,097,542.58	47,109,595.86	47,165,328.12
91		31430 - Turbogenator Units-Oil/Gas	Wilkes Generating Plant	36,042,493.86	36,075,997.50	36,075,997.50	36,912,789.88	36,912,806.91	36,952,893.27	37,813,256.62	37,828,107.59
92		31530 - Accssry Elect Equip-Oil/Gas	Wilkes Generating Plant	10,059,610.60	10,055,216.87	10,058,189.53	10,058,325.82	10,058,350.81	10,058,350.81	10,058,350.81	10,146,870.24
93		31630 - Misc Pwr Plt Equip-Oil/Gas	Wilkes Generating Plant	8,973,368.26	9,005,194.61	9,005,194.61	9,005,194.61	9,005,194.61	9,005,194.61	9,005,194.61	9,042,303.41
94		31730 - ARO Steam Prod Plnt Oil/Gas	Wilkes Generating Plant	2,122,855.72	2,122,855.72	2,122,855.72	2,122,855.72	2,122,855.72	2,122,855.72	2,122,855.72	2,122,855.72
95			**Total**	**106,092,176.57**	**112,652,925.13**	**112,678,704.43**	**113,082,256.77**	**113,693,509.24**	**113,456,150.48**	**114,328,567.11**	**114,602,532.25**
	Total Generation Plant			**4,634,864,131.18**	**4,666,739,086.22**	**4,667,991,333.69**	**4,668,870,108.96**	**4,669,968,849.83**	**4,669,905,214.98**	**4,677,986,011.52**	**4,682,758,574.30**

Southerwestern Electric Power Company
Plant In Service
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

Line No.	Category	Account	Location	Balance 12/31/16	Balance 12/31/17	Balance 1/31/18	Balance 2/28/18	Historic Balances Balance 3/31/18	Balance 4/30/18	Balance 5/31/18	Balance 6/30/18
	Total Production Plant by Account										
	Total Steam Production by Account										
96		31000- Land - Coal Fired		24,082,941.12	24,082,941.12	24,082,941.12	24,082,941.12	24,082,941.12	24,082,941.12	24,082,941.12	24,082,941.12
97		31010 - Land Rights - Coal Fired		1,886,717.17	1,886,717.17	1,886,717.17	1,886,717.17	1,886,717.17	1,886,717.17	1,886,717.17	1,886,717.17
98		31030 - Land - Oil/Gas		999,822.00	999,822.00	999,822.00	999,822.00	999,822.00	999,822.00	999,822.00	999,822.00
99		31100 - Structures, Improvemnt-Coal		549,464,164.55	552,185,323.07	552,265,190.04	552,269,844.89	548,062,047.88	547,782,078.87	548,381,020.50	548,326,856.26
100		31130 - Structures, Improvements, Oil/Gas		79,034,736.87	79,476,419.82	79,927,381.40	79,939,661.99	79,941,416.94	79,941,917.08	79,932,396.54	80,021,929.14
101		31200 - Boiler Plant Equip-Coal		2,357,950,711.22	2,433,010,117.59	2,432,948,362.46	2,432,984,645.29	2,434,299,081.20	2,434,445,684.92	2,440,917,158.66	2,446,223,670.84
102		31211 - Coal Transportation Equip		17,580,600.85	17,349,400.15	17,349,400.15	17,349,400.15	17,292,346.86	17,292,346.86	17,292,346.86	17,292,346.86
103		31230 - Boiler Plant Equip-Oil/Gas		190,741,777.68	199,001,110.41	199,028,696.83	198,486,952.10	199,053,552.25	199,007,397.58	199,038,006.03	199,205,138.94
104		31400 - Turbogenerator Units-Coal		449,824,092.36	475,183,127.61	475,180,494.95	475,309,668.16	475,209,311.34	475,211,589.39	475,212,203.72	475,220,681.56
105		31430 - Turbogenator Units-Oil/Gas		240,756,991.59	245,228,720.01	245,800,007.07	246,644,827.38	246,688,970.67	246,737,716.76	247,640,279.09	247,657,176.53
106		31500 - Accessory Elect Equip-Coal		259,990,252.59	174,296,768.46	174,471,123.95	174,458,640.02	177,633,454.65	177,650,000.08	177,645,558.51	177,904,896.38
107		31530 - Accssry Elect Equip-Oil/Gas		59,659,868.30	59,914,164.25	59,924,753.42	59,927,147.23	59,927,666.51	59,927,411.14	59,928,158.87	60,051,608.80
108		31600 - Misc Pwr Plant Equip-Coal		108,064,098.53	108,897,992.83	108,899,031.75	109,210,513.15	109,569,963.50	109,612,091.74	109,698,004.45	109,805,253.88
109		31630 - Misc Pwr Plt Equip-Oil/Gas		104,744,222.14	104,931,230.58	104,932,513.33	104,932,788.26	104,933,990.04	104,938,211.68	104,938,530.80	104,985,650.30
110		31700 - ARO Steam Production Plant		54,189,176.28	54,189,176.28	54,189,176.28	54,189,176.28	54,189,176.28	54,189,176.28	54,189,176.28	52,890,176.53
111		31730 - ARO Steam Prod Plnt Oil/Gas		6,054,113.52	6,054,113.52	6,054,113.52	6,054,113.52	6,054,113.52	6,054,113.52	6,054,113.52	6,054,113.52
112			**Total**	**4,505,024,286.77**	**4,536,687,144.87**	**4,537,939,725.44**	**4,538,726,858.71**	**4,539,824,571.93**	**4,539,759,216.19**	**4,547,836,434.12**	**4,552,608,979.83**
	Total Other Production by Account										
113		34000 - Land		1,451,852.12	1,451,852.12	1,451,852.12	1,451,852.12	1,451,852.12	1,451,852.12	1,451,852.12	1,451,852.12
114		34100 - Structures & Improvmnts		34,884,390.81	34,886,948.05	34,886,948.05	34,909,114.30	34,909,147.64	34,909,147.64	34,912,734.09	34,912,751.16
115		34400 - Generators		84,006,951.77	84,006,951.77	84,008,451.94	84,008,654.87	84,008,692.35	84,008,692.35	84,008,692.35	84,008,692.35
116		34500 - Accessory Electric Equip		8,744,937.10	8,926,714.47	8,924,881.20	8,994,154.02	8,995,110.85	8,994,746.26	8,994,738.42	8,994,738.42
117		34600 - Misc Power Plant Equip		751,712.61	779,474.94	779,474.94	779,474.94	779,474.94	781,560.42	781,560.42	781,560.42
118			**Total**	**129,839,844.41**	**130,051,941.35**	**130,051,608.25**	**130,143,250.25**	**130,144,277.90**	**130,145,998.79**	**130,149,577.40**	**130,149,594.47**
119	**Total Production Plant**			**4,634,864,131.18**	**4,666,739,086.22**	**4,667,991,333.69**	**4,668,870,108.96**	**4,669,968,849.83**	**4,669,905,214.98**	**4,677,986,011.52**	**4,682,758,574.30**
	Intangible Plant										
120		30100 - Organization Costs		12,201.82	12,201.82	12,201.82	12,201.82	12,201.82	12,201.82	12,201.82	12,201.82
121		30300 - Intangible Property		58,529,594.64	87,205,157.51	88,371,279.00	89,786,086.21	90,628,089.71	91,769,696.83	92,876,219.17	93,557,740.37
122	**Total Intangible**			**58,541,796.46**	**87,217,359.33**	**88,383,480.82**	**89,798,288.03**	**90,640,291.53**	**91,781,898.65**	**92,888,420.99**	**93,569,942.19**
	Transmission Plant										
123		35000 - Land		4,704,023.57	4,732,017.17	4,732,017.17	4,732,017.17	4,732,017.17	4,738,700.69	4,738,700.69	4,738,700.69
124		35010 - Land Rights		87,383,257.60	88,690,190.37	88,699,971.36	88,709,464.87	89,384,616.69	89,497,014.52	90,471,360.84	92,505,629.56
125		35200 - Structures and Improvements		11,123,400.63	13,209,420.68	13,226,252.16	13,266,985.86	13,540,441.42	13,568,820.08	13,719,440.21	14,555,195.26
126		35300 - Station Equipment		574,544,788.49	600,793,002.13	601,404,864.36	603,039,808.50	605,511,779.70	606,447,433.12	607,579,546.62	616,623,197.93
127		35316 - Station Equipment-SmartGrid			702,946.00	717,628.45	722,985.49	734,978.01	771,692.36	847,498.50	1,356,323.79
128		35400 - Towers and Fixtures		39,997,350.04	40,593,958.68	40,828,002.14	40,764,932.57	40,764,932.57	40,764,932.57	40,799,609.25	40,871,632.62
129		35500 - Poles and Fixtures		527,299,183.26	583,457,285.01	585,963,328.01	586,820,276.24	605,593,358.61	605,748,107.14	617,721,315.80	647,002,869.51
130		35600 - Overhead Conductors, Device		338,881,845.18	345,816,308.98	346,518,214.18	346,613,943.87	350,027,992.92	350,100,949.30	355,515,370.71	368,060,205.34
131		35616 - OVH Cond-Dev-Smart Grid			1,079,641.80	3,449,528.74	3,911,694.79	6,078,354.39	6,148,274.00	7,397,063.37	10,811,977.27
132		35700 - Underground Conduit		3,700.15	96,306.19	1,165,591.23	1,334,167.08	1,540,134.25	1,547,451.52	1,599,669.10	1,785,227.71
133		35800 - Undergrnd Conductors Device		294.76	294.76	294.76	294.76	294.76	294.76	294.76	294.76
134		35816 - Ug Cond-Dev-Smart Grid			7,380.14	26,920.70	29,692.39	33,118.45	33,238.04	33,803.43	36,389.37
135		35900 - Roads and Trails		131,946.96	131,946.96	131,946.96	131,946.96	131,946.96	131,946.96	131,946.96	131,946.96
136	**Total Transmission Plant**			**1,584,069,790.64**	**1,679,310,698.87**	**1,686,864,560.22**	**1,690,078,210.55**	**1,718,073,965.90**	**1,719,498,855.06**	**1,740,555,620.24**	**1,798,479,590.77**
	Distribution Plant										
137		36000 - Land		5,902,396.26	7,846,197.99	7,846,197.99	7,846,197.99	7,846,197.99	7,846,197.99	7,846,197.99	7,826,063.35
138		36010 - Land Rights		3,488,165.79	3,489,241.29	3,489,241.29	3,489,241.29	3,593,142.31	3,593,142.31	3,593,142.31	3,593,142.31
139		36100 - Structures and Improvements		5,400,562.49	6,250,118.10	6,291,943.46	6,307,960.88	6,313,944.06	6,315,301.12	6,331,016.81	6,337,264.62
140		36200 - Station Equipment		279,868,934.51	297,506,707.73	299,218,286.73	299,259,026.98	300,968,277.31	300,888,579.36	302,529,785.02	303,547,673.68
141		36216 - Station Equipment-SmartGrid			95,563.61	100,332.13	101,798.10	107,290.15	107,350.70	132,516.68	202,228.68
142		36400 - Poles, Towers and Fixtures		411,440,722.91	426,516,222.02	429,718,485.35	430,777,580.94	433,269,490.82	434,577,795.32	436,329,166.46	437,745,202.08
143		36500 - Overhead Conductors, Device		417,811,152.72	435,742,900.72	433,867,474.46	434,344,217.74	435,833,636.86	437,052,257.14	438,044,863.07	439,263,520.87
144		36600 - Underground Conduit		61,771,643.34	65,026,470.48	65,294,161.06	65,428,628.44	65,662,639.71	65,903,498.08	66,080,738.34	66,284,813.24
145		36700 - Undergrnd Conductors,Device		208,309,445.14	215,516,590.98	215,979,871.98	216,479,236.21	217,044,652.37	217,429,487.25	218,040,980.46	218,941,087.43
146		36800 - Line Transformers		374,216,190.13	382,054,600.25	382,950,338.74	384,008,751.32	384,297,142.37	385,026,715.02	385,183,181.51	385,796,622.58
147		36900 - Services		85,349,900.45	88,602,837.72	89,099,736.65	89,335,056.30	89,644,140.15	89,976,837.50	90,253,841.16	90,570,394.36
148		37000 - Meters		82,663,437.02	83,098,533.10	83,154,583.89	83,176,700.86	83,359,549.73	83,845,179.67	83,896,804.99	83,951,928.73

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Line No.	Category	Account	Location	Balance 12/31/16	Balance 12/31/17	Historic Balances Balance 1/31/18	Balance 2/28/18	Balance 3/31/18	Balance 4/30/18	Balance 5/31/18	Balance 6/30/18
149		37100 - Installs Customer Premises		42,682,642.06	43,401,328.50	43,397,753.80	43,418,223.00	43,477,100.07	43,537,412.24	43,564,722.74	43,584,758.37
150		37300 - Street Lghtng & Signal Sys		40,664,338.81	41,577,284.98	41,649,481.41	41,728,825.29	41,795,598.76	41,796,310.66	41,819,146.03	41,898,138.19
151	**Total Distribution Plant**			**2,019,569,531.63**	**2,096,724,597.47**	**2,102,057,888.94**	**2,105,701,445.34**	**2,113,212,802.66**	**2,117,896,064.36**	**2,123,646,103.57**	**2,129,542,838.49**
	General Plant										
152		38900 - Land		18,618,759.97	18,643,206.51	18,643,206.51	18,643,206.51	18,643,206.51	18,643,206.51	18,643,206.51	18,643,206.51
153		39000 - Structures and Improvements		101,190,997.37	102,945,448.13	103,608,215.93	103,608,213.93	103,637,968.95	103,637,015.04	104,284,566.38	104,389,360.85
154		39100 - Office Furniture, Equipment		10,089,169.68	9,987,698.68	9,987,698.68	9,987,698.68	9,987,698.68	9,987,698.68	9,989,968.04	9,989,968.04
155		39111 - Office Equip - Computers		456,077.73	56,834.41	56,834.41	56,834.41	56,834.41	56,834.41	69,158.52	69,158.52
156		39200 - Transportation Equipment		4,118,517.94	4,118,517.94	4,118,517.94	4,118,517.94	4,118,517.94	4,118,517.94	4,118,517.94	4,118,517.94
157		39300 - Stores Equipment		2,604,924.84	2,927,596.34	2,927,596.34	2,927,596.34	2,994,675.54	2,994,675.54	2,994,675.54	2,994,675.54
158		39400 - Tools		23,471,116.39	25,506,639.70	25,594,267.43	25,656,411.87	25,667,856.13	26,204,148.80	26,204,148.80	26,280,607.55
159		39500 - Laboratory Equipment		5,307,171.45	5,501,274.82	5,501,274.82	5,501,274.82	5,501,274.82	5,501,274.82	5,501,274.82	5,501,274.82
160		39600 - Power Operated Equipment		759,762.71	759,762.71	759,762.71	759,762.71	759,762.71	759,762.71	759,762.71	759,762.71
161		39700 - Communication Equipment		38,364,182.99	31,520,342.11	32,047,285.15	32,385,440.11	32,394,369.66	32,395,977.84	32,422,448.99	32,466,033.52
162		39711 - Comm Equip-Mobile Radios		347,493.95	347,493.95	347,493.95	347,493.95	347,493.95	347,493.95	347,493.95	347,493.95
163		39712 - Comm Equip-SCADA, RTU		787,456.11	787,456.11	2,453,745.40	2,464,151.88	2,475,031.89	2,438,542.25	2,434,611.02	2,434,611.02
164		39713 - Comm Equip-Masts, Antennas		121,727.73	121,727.73	121,727.73	121,727.73	121,727.73	121,727.73	121,727.73	121,727.73
165		39716 - GridSmart Communic Equip			39,067.29	508,158.29	526,399.69	559,283.34	436,448.66	436,448.66	436,448.66
166		39800 - Miscellaneous Equipment		2,612,872.68	2,551,387.54	2,575,716.37	2,578,588.31	2,579,888.75	2,579,888.75	2,588,458.63	2,588,458.63
167		39900 - Other Property - Land		65,797,750.80	65,797,750.81	65,797,750.81	65,797,750.81	65,797,750.81	65,797,750.81	65,797,750.81	65,797,750.81
168		39910 - Oth Property - Land Rights		19,879.65	19,879.65	19,879.65	19,879.65	19,879.65	19,879.65	19,879.65	19,879.65
169		39919 - ARO General Plant		939,176.70	937,494.53	937,494.53	937,494.53	937,494.53	937,494.53	937,494.53	932,027.56
170		39930 - Other Tangible Property		22,596,944.99	22,597,928.41	22,606,788.52	22,606,788.52	22,606,788.52	22,606,788.52	22,606,788.52	22,606,788.52
171	**Total General Plant**			**298,203,983.68**	**295,167,507.37**	**298,613,415.17**	**299,045,232.39**	**299,207,504.52**	**299,585,127.14**	**300,278,381.75**	**300,497,752.53**
172	**Total Plant in Service (1010 and 1060)**			**8,595,249,233.59**	**8,825,159,249.26**	**8,843,910,678.84**	**8,853,493,285.27**	**8,891,103,414.44**	**8,898,667,160.19**	**8,935,354,538.07**	**9,004,848,698.28**

Note 1: The detail for 2019 is $2,323,427 higher than actual book balances due reclassification between 1010006 and 1010001. Actual balance will be adjusted when actual December balances are provided.

Note 2: In May 2018 the PowerPlant CPR for BU 194 was closed before the OAJ266 transfer from 107 to 106 was run. A manual journal entry was made to the general ledger to record a $44.6 million transfer from 107 to 106. This put Pow

Southerwestern Electric Power Company
Plant In Service
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing fiscal or calendar y

Line No.	Category	Account	Location	Balance 7/31/18	Forecasted Balances Balance 8/31/18	Balance 9/30/18	Balance 10/31/18	Balance 11/30/18	Balance 12/31/18	Balance 12/31/19 (Note 1)
	Generation Plant									
	Arsenal Hill									
1		31030 - Land - Oil/Gas	Arsenal Hill Generating Plant	370,798.41	370,798.00	370,798.00	370,798.00	370,798.00	370,798.00	370,798.00
2		31130 - Struct, Improvemnts-Oil/Gas	Arsenal Hill Generating Plant	5,798,815.00	5,798,815.00	5,798,815.00	5,798,815.00	5,798,815.00	5,798,815.00	5,798,815.00
3		31230 - Boiler Plant Equip-Oil/Gas	Arsenal Hill Generating Plant	6,859,389.49	6,849,806.00	6,873,244.00	6,900,923.00	6,928,849.00	6,938,642.00	7,001,242.00
4		31430 - Turbogenator Units-Oil/Gas	Arsenal Hill Generating Plant	4,779,907.55	4,773,230.00	4,789,562.00	4,808,850.00	4,828,309.00	4,835,133.00	4,878,754.00
5		31530 - Accssry Elect Equip-Oil/Gas	Arsenal Hill Generating Plant	1,210,370.51	1,208,680.00	1,212,815.00	1,217,699.00	1,222,627.00	1,224,353.00	1,235,399.00
6		31630 - Misc Pwr Plt Equip-Oil/Gas	Arsenal Hill Generating Plant	7,033,250.60	7,023,424.00	7,047,455.00	7,075,837.00	7,104,470.00	7,114,514.00	7,178,700.00
7		31730 - ARO Steam Prod Plnt Oil/Gas	Arsenal Hill Generating Plant	507,714.26	507,714.00	507,714.00	507,714.00	507,714.00	507,714.00	507,714.00
8			**Total**	**26,560,245.82**	**26,532,467.00**	**26,600,403.00**	**26,680,636.00**	**26,761,582.00**	**26,789,969.00**	**26,971,422.00**
	Dolet Hills									
9		31000 - Land - Coal Fired	Dolet Hills Generating Plant	1,510,614.56	1,510,615.00	1,510,615.00	1,510,615.00	1,510,615.00	1,510,615.00	1,510,615.00
10		31100 - Structures, Improvemnt-Coal	Dolet Hills Generating Plant	56,188,715.31	56,129,480.00	56,274,345.00	56,445,434.00	56,618,040.00	56,678,577.00	57,065,505.00
11		31200 - Boiler Plant Equip-Coal	Dolet Hills Generating Plant	219,940,636.03	219,708,771.00	220,275,820.00	220,945,513.00	221,621,150.00	221,858,121.00	223,372,681.00
12		31400 - Turbogenerator Units-Coal	Dolet Hills Generating Plant	39,642,457.38	39,600,666.00	39,702,871.00	39,823,578.00	39,945,356.00	39,988,064.00	40,261,051.00
13		31500 - Accessory Elect Equip-Coal	Dolet Hills Generating Plant	12,041,188.34	12,028,494.00	12,059,539.00	12,096,203.00	12,133,192.00	12,146,164.00	12,229,082.00
14		31600 - Misc Pwr Plant Equip-Coal	Dolet Hills Generating Plant	16,105,620.77	16,088,642.00	16,130,165.00	16,179,205.00	16,228,680.00	16,246,032.00	16,356,939.00
15		31700 - ARO Steam Production Plant	Dolet Hills Generating Plant	1,230,657.52	1,230,658.00	1,230,658.00	1,230,658.00	1,230,658.00	1,230,658.00	1,230,658.00
16			**Total**	**346,659,889.91**	**346,297,326.00**	**347,184,013.00**	**348,231,206.00**	**349,287,691.00**	**349,658,231.00**	**352,026,531.00**
	Flint Creek									
17		31000 - Land - Coal Fired	Flint Creek Generating Plant	3,364,925.23	3,364,925.00	3,364,925.00	3,364,925.00	3,364,925.00	3,364,925.00	3,364,925.00
18		31100 - Structures, Improvemnt-Coal	Flint Creek Generating Plant	26,759,507.69	26,729,945.00	26,802,243.00	26,887,628.00	26,973,771.00	27,003,982.00	27,197,087.00
19		31200 - Boiler Plant Equip-Coal	Flint Creek Generating Plant	295,043,458.89	294,717,512.00	295,514,649.00	296,456,084.00	297,405,872.00	297,738,988.00	299,868,107.00
20		31211 - Coal Transportation Equip	Flint Creek Generating Plant	6,725,198.35	6,725,198.00	6,725,198.00	6,725,198.00	6,725,198.00	6,725,198.00	6,725,198.00
21		31400 - Turbogenerator Units-Coal	Flint Creek Generating Plant	15,292,265.92	15,275,372.00	15,316,688.00	15,365,483.00	15,414,711.00	15,431,977.00	15,542,330.00
22		31500 - Accessory Elect Equip-Coal	Flint Creek Generating Plant	8,783,638.43	8,773,935.00	8,797,666.00	8,825,693.00	8,853,969.00	8,863,884.00	8,927,269.00
23		31600 - Misc Pwr Plant Equip-Coal	Flint Creek Generating Plant	6,074,377.62	6,067,667.00	6,084,079.00	6,103,461.00	6,123,015.00	6,129,876.00	6,173,710.00
24		31700 - ARO Steam Production Plant	Flint Creek Generating Plant	9,719,253.01	9,719,253.00	9,719,253.00	9,719,253.00	9,719,253.00	9,719,253.00	9,719,253.00
25			**Total**	**371,762,625.14**	**371,373,807.00**	**372,324,701.00**	**373,447,725.00**	**374,580,714.00**	**374,978,083.00**	**377,517,879.00**
	Knox Lee									
26		31030 - Land - Oil/Gas	Knox Lee Generating Plant	102,781.04	102,781.00	102,781.00	102,781.00	102,781.00	102,781.00	102,781.00
27		31130 - Struct, Improvemnts-Oil/Gas	Knox Lee Generating Plant	8,323,697.13	8,314,731.00	8,336,658.00	8,362,555.00	8,388,681.00	8,397,844.00	8,456,411.00
28		31230 - Boiler Plant Equip-Oil/Gas	Knox Lee Generating Plant	35,475,381.72	35,437,169.00	35,530,623.00	35,640,993.00	35,752,342.00	35,791,395.00	36,041,006.00
29		31430 - Turbogenator Units-Oil/Gas	Knox Lee Generating Plant	21,777,900.93	21,754,443.00	21,811,812.00	21,879,567.00	21,947,924.00	21,971,898.00	22,125,131.00
30		31530 - Accssry Elect Equip-Oil/Gas	Knox Lee Generating Plant	4,056,412.74	4,052,043.00	4,062,729.00	4,075,349.00	4,088,082.00	4,092,547.00	4,121,088.00
31		31630 - Misc Pwr Plt Equip-Oil/Gas	Knox Lee Generating Plant	1,877,079.11	1,875,057.00	1,880,002.00	1,885,842.00	1,891,734.00	1,893,801.00	1,907,008.00
32		31730 - ARO Steam Prod Plnt Oil/Gas	Knox Lee Generating Plant	2,036,607.78	2,036,608.00	2,036,608.00	2,036,608.00	2,036,608.00	2,036,608.00	2,036,608.00
33			**Total**	**73,649,860.45**	**73,572,832.00**	**73,761,213.00**	**73,983,695.00**	**74,208,152.00**	**74,286,874.00**	**74,790,033.00**
	Lieberman									
34		31030 - Land - Oil/Gas	Lieberman Generating Plant	24,026.38	24,026.00	24,026.00	24,026.00	24,026.00	24,026.00	24,026.00
35		31130 - Struct, Improvemnts-Oil/Gas	Lieberman Generating Plant	3,829,290.16	3,829,290.00	3,829,290.00	3,829,290.00	3,829,290.00	3,829,290.00	3,829,290.00
36		31230 - Boiler Plant Equip-Oil/Gas	Lieberman Generating Plant	18,441,275.51	18,415,146.00	18,479,049.00	18,554,519.00	18,630,659.00	18,657,360.00	18,828,041.00
37		31430 - Turbogenator Units-Oil/Gas	Lieberman Generating Plant	11,678,559.77	11,662,013.00	11,702,481.00	11,750,275.00	11,798,493.00	11,815,404.00	11,923,493.00
38		31530 - Accssry Elect Equip-Oil/Gas	Lieberman Generating Plant	3,431,323.47	3,431,323.00	3,431,323.00	3,431,323.00	3,431,323.00	3,431,323.00	3,431,323.00
39		31630 - Misc Pwr Plt Equip-Oil/Gas	Lieberman Generating Plant	2,137,094.75	2,137,095.00	2,137,095.00	2,137,095.00	2,137,095.00	2,137,095.00	2,137,095.00
40		31730 - ARO Steam Prod Plnt Oil/Gas	Lieberman Generating Plant	1,263,344.24	1,263,344.00	1,263,344.00	1,263,344.00	1,263,344.00	1,263,344.00	1,263,344.00
41			**Total**	**40,804,914.28**	**40,762,237.00**	**40,866,608.00**	**40,989,872.00**	**41,114,230.00**	**41,157,842.00**	**41,436,612.00**

Southerwestern Electric Power Company
Plant In Service
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing fiscal or calendar y

Line No.	Category	Account	Location	Balance 7/31/18	Forecasted Balances: Balance 8/31/18	Balance 9/30/18	Balance 10/31/18	Balance 11/30/18	Balance 12/31/18	Balance 12/31/19
	Lone Star									
42		31030 - Land - Oil/Gas	Lone Star Generating Plant	58,486.72	58,487.00	58,487.00	58,487.00	58,487.00	58,487.00	58,487.00
43		31130 - Struct, Improvemnts-Oil/Gas	Lone Star Generating Plant	934,757.43	934,757.00	934,757.00	934,757.00	934,757.00	934,757.00	934,757.00
44		31230 - Boiler Plant Equip-Oil/Gas	Lone Star Generating Plant	4,148,919.64	4,148,920.00	4,148,920.00	4,148,920.00	4,148,920.00	4,148,920.00	4,219,649.00
45		31430 - Turbogenator Units-Oil/Gas	Lone Star Generating Plant	2,586,137.30	2,586,137.00	2,586,137.00	2,586,137.00	2,586,137.00	2,586,137.00	2,630,224.00
46		31530 - Accssry Elect Equip-Oil/Gas	Lone Star Generating Plant	879,416.72	879,417.00	879,417.00	879,417.00	879,417.00	879,417.00	879,417.00
47		31630 - Misc Pwr Plt Equip-Oil/Gas	Lone Star Generating Plant	201,388.92	201,389.00	201,389.00	201,389.00	201,389.00	201,389.00	201,389.00
48		31730 - ARO Steam Prod Plnt Oil/Gas	Lone Star Generating Plant	123,591.52	123,591.00	123,591.00	123,591.00	123,591.00	123,591.00	123,591.00
49			**Total**	**8,932,698.25**	**8,932,698.00**	**8,932,698.00**	**8,932,698.00**	**8,932,698.00**	**8,932,698.00**	**9,047,514.00**
	Mattison									
50		34000 - Land	Mattison Generating Plant	1,451,852.12	1,451,852.00	1,451,852.00	1,451,852.00	1,451,852.00	1,451,852.00	1,451,852.00
51		34100 - Structures & Improvmnts	Mattison Generating Plant	34,912,751.16	34,875,825.00	34,966,132.00	35,072,786.00	35,180,387.00	35,218,126.00	35,459,332.00
52		34400 - Generators	Mattison Generating Plant	84,008,692.35	83,919,839.00	84,137,140.00	84,393,777.00	84,652,691.00	84,743,499.00	85,323,902.00
53		34500 - Accessory Electric Equip	Mattison Generating Plant	8,994,738.42	8,985,225.00	9,008,491.00	9,035,969.00	9,063,691.00	9,073,414.00	9,135,558.00
54		34600 - Misc Power Plant Equip	Mattison Generating Plant	784,464.17	783,634.00	785,664.00	788,060.00	790,478.00	791,326.00	796,744.00
55			**Total**	**130,152,498.22**	**130,016,375.00**	**130,349,279.00**	**130,742,444.00**	**131,139,099.00**	**131,278,217.00**	**132,167,388.00**
	Pirkey									
56		31000 - Land - Coal Fired	Pirkey Generating Plant	5,843,028.51	5,843,029.00	5,843,029.00	5,843,029.00	5,843,029.00	5,843,029.00	5,843,028.00
57		31100 - Structures, Improvemnt-Coal	Pirkey Generating Plant	108,542,724.63	108,542,725.00	108,542,725.00	108,542,725.00	108,542,725.00	108,542,725.00	108,542,725.00
58		31200 - Boiler Plant Equip-Coal	Pirkey Generating Plant	368,113,727.70	367,551,760.00	368,926,108.00	370,549,236.00	372,186,768.00	372,761,096.00	376,431,917.00
59		31400 - Turbogenerator Units-Coal	Pirkey Generating Plant	50,945,628.34	50,945,628.00	50,945,628.00	50,945,628.00	50,945,628.00	50,945,628.00	50,945,628.00
60		31500 - Accessory Elect Equip-Coal	Pirkey Generating Plant	18,049,321.84	18,021,768.00	18,089,154.00	18,168,740.00	18,249,031.00	18,277,191.00	18,457,178.00
61		31600 - Misc Pwr Plant Equip-Coal	Pirkey Generating Plant	18,446,732.68	18,418,572.00	18,487,442.00	18,568,780.00	18,650,839.00	18,679,619.00	18,863,568.00
62		31700 - ARO Steam Production Plant	Pirkey Generating Plant	20,646,275.80	20,646,276.00	20,646,276.00	20,646,276.00	20,646,276.00	20,646,276.00	20,646,276.00
63			**Total**	**590,587,439.50**	**589,969,758.00**	**591,480,362.00**	**593,264,414.00**	**595,064,296.00**	**595,695,564.00**	**599,730,320.00**
	Stall									
64		31130 - Struct, Improvemnts-Oil/Gas	Arsenal Hill Generating Plan	53,286,731.69	53,231,000.00	53,367,297.00	53,528,266.00	53,690,663.00	53,747,621.00	54,111,663.00
65		31230 - Boiler Plant Equip-Oil/Gas	Arsenal Hill Generating Plan	87,182,639.11	87,091,457.00	87,314,453.00	87,577,815.00	87,843,514.00	87,936,702.00	88,532,314.00
66		31430 - Turbogenator Units-Oil/Gas	Arsenal Hill Generating Plan	169,008,176.97	168,831,415.00	169,263,704.00	169,774,245.00	170,289,317.00	170,469,967.00	171,624,593.00
67		31530 - Accssry Elect Equip-Oil/Gas	Arsenal Hill Generating Plan	40,329,265.40	40,287,086.00	40,390,240.00	40,512,067.00	40,634,975.00	40,678,082.00	40,953,603.00
68		31630 - Misc Pwr Plt Equip-Oil/Gas	Arsenal Hill Generating Plan	84,695,483.91	84,606,903.00	84,823,537.00	85,079,386.00	85,337,505.00	85,428,034.00	86,006,653.00
69			**Total**	**434,502,297.08**	**434,047,861.00**	**435,159,231.00**	**436,471,779.00**	**437,795,974.00**	**438,260,406.00**	**441,228,826.00**
	Turk									
70		31000 - Land - Coal Fired	Turk Generating Plant	11,468,899.32	11,468,899.00	11,468,899.00	11,468,899.00	11,468,899.00	11,468,899.00	11,468,899.00
71		31010 - Land Rights - Coal Fired	Turk Generating Plant	1,886,717.17	1,886,717.00	1,886,717.00	1,886,717.00	1,886,717.00	1,886,717.00	1,886,717.00
72		31100 - Structures, Improvemnt-Coal	Turk Generating Plant	285,601,333.04	285,250,189.00	286,108,949.00	287,123,161.00	288,146,372.00	288,505,241.00	290,798,952.00
73		31200 - Boiler Plant Equip-Coal	Turk Generating Plant	986,401,347.52	985,188,575.00	988,154,535.00	991,657,391.00	995,191,326.00	996,430,785.00	1,004,352,733.00
74		31400 - Turbogenerator Units-Coal	Turk Generating Plant	232,599,491.86	232,599,492.00	232,599,492.00	232,599,492.00	232,599,492.00	232,599,492.00	232,599,492.00
75		31500 - Accessory Elect Equip-Coal	Turk Generating Plant	93,356,005.32	93,241,225.00	93,521,932.00	93,853,453.00	94,187,916.00	94,305,219.00	95,054,977.00
76		31600 - Misc Pwr Plant Equip-Coal	Turk Generating Plant	48,018,866.19	47,959,827.00	48,104,213.00	48,274,735.00	48,446,770.00	48,507,106.00	48,892,754.00
77		31700 - ARO Steam Production Plant	Turk Generating Plant	2,179,312.62	2,179,313.00	2,179,313.00	2,179,313.00	2,179,313.00	2,179,313.00	2,179,313.00
78			**Total**	**1,661,511,973.04**	**1,659,774,237.00**	**1,664,024,050.00**	**1,669,043,161.00**	**1,674,106,805.00**	**1,675,882,772.00**	**1,687,233,837.00**
	Welsh									
79		31000 - Land - Coal Fired	Welsh Generating Plant	1,895,473.50	1,895,474.00	1,895,474.00	1,895,474.00	1,895,474.00	1,895,473.00	1,895,473.00
80		31100 - Structures, Improvemnt-Coal	Welsh Generating Plant	72,166,675.74	72,089,373.00	72,278,424.00	72,501,697.00	72,726,951.00	72,805,953.00	73,310,899.00
81		31200 - Boiler Plant Equip-Coal	Welsh Generating Plant	577,718,734.69	577,099,902.00	578,613,319.00	580,400,691.00	582,203,924.00	582,836,369.00	586,878,638.00
82		31211 - Coal Transportation Equip	Welsh Generating Plant	10,567,148.51	10,555,829.00	10,583,511.00	10,616,205.00	10,649,188.00	10,660,755.00	10,734,693.00
83		31400 - Turbogenerator Units-Coal	Welsh Generating Plant	141,612,089.76	141,460,400.00	141,831,373.00	142,269,499.00	142,711,513.00	142,866,540.00	143,857,393.00
84		31500 - Accessory Elect Equip-Coal	Welsh Generating Plant	45,690,452.66	45,641,511.00	45,761,203.00	45,902,563.00	46,045,176.00	46,095,197.00	46,414,890.00
85		31600 - Misc Pwr Plant Equip-Coal	Welsh Generating Plant	21,215,410.19	21,192,685.00	21,248,262.00	21,313,899.00	21,380,119.00	21,403,344.00	21,551,787.00
86		31700 - ARO Steam Production Plant	Welsh Generating Plant	19,114,677.58	19,114,678.00	19,114,678.00	19,114,678.00	19,114,678.00	19,114,678.00	19,114,678.00
87			**Total**	**889,980,662.63**	**889,049,852.00**	**891,326,244.00**	**894,014,706.00**	**896,727,023.00**	**897,678,309.00**	**903,758,451.00**
	Wilkes									
88		31030 - Land - Oil/Gas	Wilkes Generating Plant	443,729.45	443,729.00	443,729.00	443,729.00	443,729.00	443,729.00	443,729.00
89		31130 - Struct, Improvemnts-Oil/Gas	Wilkes Generating Plant	7,852,299.18	7,843,899.00	7,864,443.00	7,888,707.00	7,913,186.00	7,921,771.00	7,976,646.00
90		31230 - Boiler Plant Equip-Oil/Gas	Wilkes Generating Plant	47,176,722.10	47,126,250.00	47,249,684.00	47,395,460.00	47,542,529.00	47,594,111.00	47,923,795.00
91		31430 - Turbogenator Units-Oil/Gas	Wilkes Generating Plant	37,828,011.20	37,787,542.00	37,886,514.00	38,003,403.00	38,121,329.00	38,162,689.00	38,427,041.00
92		31530 - Accssry Elect Equip-Oil/Gas	Wilkes Generating Plant	10,146,499.41	10,135,644.00	10,162,192.00	10,193,544.00	10,225,175.00	10,236,269.00	10,307,177.00
93		31630 - Misc Pwr Plt Equip-Oil/Gas	Wilkes Generating Plant	9,042,812.83	9,033,139.00	9,056,798.00	9,084,740.00	9,112,931.00	9,122,818.00	9,186,011.00
94		31730 - ARO Steam Prod Plnt Oil/Gas	Wilkes Generating Plant	2,122,855.72	2,122,856.00	2,122,856.00	2,122,856.00	2,122,856.00	2,122,856.00	2,122,856.00
95			**Total**	**114,612,929.89**	**114,493,059.00**	**114,786,216.00**	**115,132,439.00**	**115,481,735.00**	**115,604,243.00**	**116,387,255.00**
	Total Generation Plant			**4,689,718,034.21**	**4,684,822,509.00**	**4,696,795,018.00**	**4,710,934,775.00**	**4,725,199,999.00**	**4,730,203,208.00**	**4,762,296,068.00**

Southerwestern Electric Power Company
Plant In Service
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing fiscal or calendar y

Line No.	Category	Account	Location	Balance 7/31/18	Forecasted Balances: Balance 8/31/18	Balance 9/30/18	Balance 10/31/18	Balance 11/30/18	Balance 12/31/18	Balance 12/31/19
	Total Production Plant by Account									
	Total Steam Production by Account									
96		31000- Land - Coal Fired		24,082,941.12	24,082,942.00	24,082,942.00	24,082,942.00	24,082,942.00	24,082,941.00	24,082,940.00
97		31010 - Land Rights - Coal Fired		1,886,717.17	1,886,717.00	1,886,717.00	1,886,717.00	1,886,717.00	1,886,717.00	1,886,717.00
98		31030 - Land - Oil/Gas		999,822.00	999,821.00	999,821.00	999,821.00	999,821.00	999,821.00	999,821.00
99		31100 - Structures, Improvemnt-Coal		549,258,956.41	548,741,712.00	550,006,686.00	551,500,645.00	553,007,859.00	553,536,478.00	556,915,168.00
100		31130 - Structures, Improvements, Oil/Gas		80,025,590.59	79,952,492.00	80,131,260.00	80,342,390.00	80,555,392.00	80,630,098.00	81,107,582.00
101		31200 - Boiler Plant Equip-Coal		2,447,217,904.83	2,444,266,520.00	2,451,484,431.00	2,460,008,915.00	2,468,609,040.00	2,471,625,359.00	2,490,904,076.00
102		31211 - Coal Transportation Equip		17,292,346.86	17,281,027.00	17,308,709.00	17,341,403.00	17,374,386.00	17,385,953.00	17,459,891.00
103		31230 - Boiler Plant Equip-Oil/Gas		199,284,327.57	199,068,748.00	199,595,973.00	200,218,630.00	200,846,813.00	201,067,130.00	202,546,047.00
104		31400 - Turbogenerator Units-Coal		480,091,933.26	479,881,558.00	480,396,052.00	481,003,680.00	481,616,700.00	481,831,701.00	483,205,894.00
105		31430 - Turbogenator Units-Oil/Gas		247,658,693.72	247,394,780.00	248,040,210.00	248,802,477.00	249,571,509.00	249,841,228.00	251,609,236.00
106		31500 - Accessory Elect Equip-Coal		177,920,606.59	177,706,933.00	178,229,494.00	178,846,652.00	179,469,284.00	179,687,655.00	181,083,396.00
107		31530 - Accssry Elect Equip-Oil/Gas		60,053,288.25	59,994,193.00	60,138,716.00	60,309,399.00	60,481,599.00	60,541,991.00	60,928,007.00
108		31600 - Misc Pwr Plant Equip-Coal		109,861,007.45	109,727,393.00	110,054,161.00	110,440,080.00	110,829,423.00	110,965,977.00	111,838,758.00
109		31630 - Misc Pwr Plt Equip-Oil/Gas		104,987,110.12	104,877,007.00	105,146,276.00	105,464,289.00	105,785,124.00	105,897,651.00	106,616,856.00
110		31700 - ARO Steam Production Plant		52,890,176.53	52,890,178.00	52,890,178.00	52,890,178.00	52,890,178.00	52,890,178.00	52,890,178.00
111		31730 - ARO Steam Prod Plnt Oil/Gas		6,054,113.52	6,054,113.00	6,054,113.00	6,054,113.00	6,054,113.00	6,054,113.00	6,054,113.00
112			**Total**	**4,559,565,535.99**	**4,554,806,134.00**	**4,566,445,739.00**	**4,580,192,331.00**	**4,594,060,900.00**	**4,598,924,991.00**	**4,630,128,680.00**
	Total Other Production by Account									
113		34000 - Land		1,451,852.12	1,451,852.00	1,451,852.00	1,451,852.00	1,451,852.00	1,451,852.00	1,451,852.00
114		34100 - Structures & Improvmnts		34,912,751.16	34,875,825.00	34,966,132.00	35,072,786.00	35,180,387.00	35,218,126.00	35,459,332.00
115		34400 - Generators		84,008,692.35	83,919,839.00	84,137,140.00	84,393,777.00	84,652,691.00	84,743,499.00	85,323,902.00
116		34500 - Accessory Electric Equip		8,994,738.42	8,985,225.00	9,008,491.00	9,035,969.00	9,063,691.00	9,073,414.00	9,135,558.00
117		34600 - Misc Power Plant Equip		784,464.17	783,634.00	785,664.00	788,060.00	790,478.00	791,326.00	796,744.00
118			**Total**	**130,152,498.22**	**130,016,375.00**	**130,349,279.00**	**130,742,444.00**	**131,139,099.00**	**131,278,217.00**	**132,167,388.00**
119	**Total Production Plant**			**4,689,718,034.21**	**4,684,822,509.00**	**4,696,795,018.00**	**4,710,934,775.00**	**4,725,199,999.00**	**4,730,203,208.00**	**4,762,296,068.00**
	Intangible Plant									
120		30100 - Organization Costs		12,201.82	12,202.00	12,202.00	12,202.00	12,202.00	12,202.00	12,202.00
121		30300 - Intangible Property		97,658,520.05	95,941,070.00	102,342,820.00	109,058,631.00	114,867,291.00	122,223,886.00	149,950,443.00
122	**Total Intangible**			**97,670,721.87**	**95,953,272.00**	**102,355,022.00**	**109,070,833.00**	**114,879,493.00**	**122,236,088.00**	**149,962,645.00**
	Transmission Plant									
123		35000 - Land		4,775,088.27	4,775,088.00	4,775,088.00	4,775,088.00	4,775,088.00	4,775,088.00	4,775,088.00
124		35010 - Land Rights		92,545,875.10	92,657,679.00	92,779,192.00	93,093,822.00	93,626,622.00	94,778,104.00	103,189,338.00
125		35200 - Structures and Improvements		14,717,824.62	14,735,605.00	14,754,930.00	14,804,966.00	14,889,699.00	15,072,822.00	16,410,486.00
126		35300 - Station Equipment		617,889,082.71	618,635,548.00	619,446,837.00	621,547,491.00	625,104,765.00	632,792,716.00	688,950,910.00
127		35316 - Station Equipment-SmartGrid		1,361,999.67	1,363,645.00	1,365,433.00	1,370,064.00	1,377,905.00	1,394,851.00	1,518,640.00
128		35400 - Towers and Fixtures		40,872,805.99	40,922,184.00	40,975,850.00	41,114,806.00	41,350,117.00	41,858,668.00	45,573,481.00
129		35500 - Poles and Fixtures		647,359,523.67	648,141,592.00	648,991,576.00	651,192,422.00	654,919,361.00	662,973,992.00	721,810,667.00
130		35600 - Overhead Conductors, Device		369,022,084.10	369,467,896.00	369,952,422.00	371,206,997.00	373,331,508.00	377,922,986.00	411,462,360.00
131		35616 - OVH Cond-Dev-Smart Grid		11,491,174.30	11,505,057.00	11,520,145.00	11,559,211.00	11,625,368.00	11,768,344.00	12,812,746.00
132		35700 - Underground Conduit		2,069,255.24	2,071,755.00	2,074,472.00	2,081,507.00	2,093,420.00	2,119,166.00	2,307,231.00
133		35800 - Undergrnd Conductors Device		294.76	295.00	295.00	295.00	295.00	295.00	295.00
134		35816 - Ug Cond-Dev-Smart Grid		40,045.67	40,094.00	40,147.00	40,283.00	40,513.00	41,012.00	44,652.00
135		35900 - Roads and Trails		131,946.96	131,947.00	131,947.00	131,947.00	131,947.00	131,947.00	131,947.00
136	**Total Transmission Plant**			**1,802,277,001.06**	**1,804,448,385.00**	**1,806,808,334.00**	**1,812,918,899.00**	**1,823,266,608.00**	**1,845,629,991.00**	**2,008,987,841.00**
	Distribution Plant									
137		36000 - Land		7,826,063.35	7,826,063.00	7,826,063.00	7,826,063.00	7,826,063.00	7,826,063.00	7,826,063.00
138		36010 - Land Rights		3,593,142.31	3,593,142.00	3,593,142.00	3,593,142.00	3,593,142.00	3,593,142.00	3,593,142.00
139		36100 - Structures and Improvements		7,775,647.82	7,806,069.00	7,839,075.00	7,919,037.00	7,956,457.00	7,992,932.00	8,420,475.00
140		36200 - Station Equipment		307,125,092.92	308,326,664.00	309,630,343.00	312,788,724.00	314,266,758.00	315,707,469.00	332,594,550.00
141		36216 - Station Equipment-SmartGrid		297,020.80	298,183.00	299,444.00	302,498.00	303,928.00	305,321.00	321,655.00
142		36400 - Poles, Towers and Fixtures		438,848,632.49	440,565,548.00	442,428,365.00	446,941,350.00	449,053,302.00	451,111,922.00	475,241,737.00
143		36500 - Overhead Conductors, Device		439,915,585.50	441,636,676.00	443,504,021.00	448,027,977.00	450,145,065.00	452,208,690.00	476,397,175.00
144		36600 - Underground Conduit		66,522,478.15	66,782,735.00	67,065,109.00	67,749,205.00	68,069,344.00	68,381,398.00	72,039,095.00
145		36700 - Undergrnd Conductors,Device		219,395,395.27	220,253,740.00	221,185,026.00	223,441,221.00	224,497,058.00	225,526,232.00	237,589,548.00
146		36800 - Line Transformers		386,576,527.38	388,088,938.00	389,729,871.00	393,705,306.00	395,565,699.00	397,379,113.00	418,634,780.00
147		36900 - Services		90,906,355.51	91,262,010.00	91,647,888.00	92,582,741.00	93,020,226.00	93,446,664.00	98,445,094.00
148		37000 - Meters		84,378,024.35	84,708,138.00	85,066,304.00	85,934,022.00	86,340,090.00	86,735,904.00	91,375,372.00

Southerwestern Electric Power Company
Plant In Service
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing fiscal or calendar y

Line No.	Category	Account	Location	Balance 7/31/18	Forecasted Balances Balance 8/31/18	Balance 9/30/18	Balance 10/31/18	Balance 11/30/18	Balance 12/31/18	Balance 12/31/19
149		37100 - Installs Customer Premises		43,598,030.83	43,768,600.00	43,953,664.00	44,402,013.00	44,611,828.00	44,816,344.00	47,213,554.00
150		37300 - Street Lghtng & Signal Sys		41,871,653.04	42,035,468.00	42,213,204.00	42,643,800.00	42,845,306.00	43,041,724.00	45,344,009.00
151	**Total Distribution Plant**			**2,138,629,649.72**	**2,146,951,974.00**	**2,155,981,519.00**	**2,177,857,099.00**	**2,188,094,266.00**	**2,198,072,918.00**	**2,315,036,249.00**
	General Plant									
152		38900 - Land		18,643,206.51	18,643,207.00	18,643,207.00	18,643,207.00	18,643,207.00	18,643,207.00	18,643,206.00
153		39000 - Structures and Improvements		104,459,188.53	104,517,009.00	104,489,278.00	104,493,566.00	104,508,963.00	104,891,737.00	104,289,539.00
154		39100 - Office Furniture, Equipment		9,989,968.04	9,989,968.00	9,989,968.00	9,989,968.00	9,989,968.00	9,989,968.00	9,989,968.00
155		39111 - Office Equip - Computers		69,158.52	69,197.00	69,178.00	69,181.00	69,191.00	69,445.00	69,045.00
156		39200 - Transportation Equipment		4,118,517.94	4,118,518.00	4,118,518.00	4,118,518.00	4,118,518.00	4,118,518.00	4,118,518.00
157		39300 - Stores Equipment		2,994,675.54	2,996,333.00	2,995,538.00	2,995,661.00	2,996,102.00	3,007,076.00	2,989,813.00
158		39400 - Tools		26,341,826.68	26,356,408.00	26,349,414.00	26,350,496.00	26,354,378.00	26,450,904.00	26,299,046.00
159		39500 - Laboratory Equipment		5,501,274.82	5,501,275.00	5,501,275.00	5,501,275.00	5,501,275.00	5,501,275.00	5,501,275.00
160		39600 - Power Operated Equipment		759,762.71	759,763.00	759,763.00	759,763.00	759,763.00	759,763.00	759,763.00
161		39700 - Communication Equipment		33,064,030.07	33,082,332.00	33,073,553.00	33,074,911.00	33,079,785.00	33,200,943.00	33,010,333.00
162		39711 - Comm Equip-Mobile Radios		347,493.95	347,494.00	347,494.00	347,494.00	347,494.00	347,494.00	347,494.00
163		39712 - Comm Equip-SCADA, RTU		2,434,611.02	2,435,959.00	2,435,312.00	2,435,412.00	2,435,771.00	2,444,692.00	2,430,659.00
164		39713 - Comm Equip-Masts, Antennas		121,727.73	121,728.00	121,728.00	121,728.00	121,728.00	121,728.00	121,728.00
165		39716 - GridSmart Communic Equip		436,448.66	436,690.00	436,574.00	436,592.00	436,657.00	438,256.00	435,739.00
166		39800 - Miscellaneous Equipment		2,596,115.53	2,597,553.00	2,596,863.00	2,596,970.00	2,597,353.00	2,606,866.00	2,591,901.00
167		39900 - Other Property - Land		65,797,750.81	65,834,171.00	65,816,702.00	65,819,405.00	65,829,103.00	66,070,209.00	65,690,891.00
168		39910 - Oth Property - Land Rights		19,879.65	19,880.00	19,880.00	19,880.00	19,880.00	19,880.00	19,880.00
169		39919 - ARO General Plant		932,027.56	932,543.00	932,296.00	932,334.00	932,472.00	935,887.00	930,512.00
170		39930 - Other Tangible Property		22,606,788.52	22,606,789.00	22,606,789.00	22,606,789.00	22,606,789.00	22,606,789.00	22,606,788.00
171	**Total General Plant**			**301,234,452.79**	**301,366,817.00**	**301,303,330.00**	**301,313,150.00**	**301,348,397.00**	**302,224,637.00**	**300,846,098.00**
172	**Total Plant in Service (1010 and 1060)**			**9,029,529,859.65**	**9,033,542,957.00**	**9,063,243,223.00**	**9,112,094,756.00**	**9,152,788,763.00**	**9,198,366,842.00**	**9,537,128,901.00**

Note 1: The detail for 2019 is $2,323,427 higher than actual book balance
Note 2: In May 2018 the PowerPlant CPR for BU 194 was closed before therPlant and the general ledger out of balance for account 106 for May 2018.

Southerwestern Electric Power Company
Accumulated Provision for Depreciation
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

Line No.	Accoun	Plant	12/31/2016	Historic Balances 12/31/2017	1/31/2018	2/28/2018	3/31/2018	4/30/2018	5/31/2018	6/30/2018	7/31/2018
		PRODUCTION PLANT									
		STEAM PRODUCTION									
1	310	Land	9,535	9,535	9,535	9,535	9,535	9,535	9,535	9,535	9,535
2	311	Structures & Improvmnts	252,444,362	268,423,693	269,590,688	270,724,327	267,609,040	268,468,737	269,615,857	269,892,752	270,859,389
3	312	Boiler Plant Equip	699,891,244	763,626,176	768,163,122	772,655,375	777,447,623	782,281,068	784,368,245	788,190,350	792,501,871
4	314	Turbogenerator Units	220,586,457	228,763,851	230,140,528	231,564,461	232,960,341	234,391,898	234,973,910	236,357,705	237,243,768
5	315	Accessory Elect Equip	63,322,487	70,035,326	70,502,238	70,970,041	70,643,131	71,108,258	71,587,828	71,763,770	72,221,378
6	316	Misc Pwr Plant Equip	70,600,994	76,219,902	76,701,322	77,186,536	77,670,028	78,155,969	78,637,399	79,096,725	79,514,749
7	31700	ARO Steam Production Plant	4,511,005	6,372,080	6,527,169	6,682,259	6,837,348	6,992,438	7,147,527	7,302,617	7,453,908
8	31730	ARO Steam Production Plant Oi	2,520,399	2,795,976	2,818,788	2,841,600	2,864,412	2,887,224	2,910,036	2,932,848	2,955,660
9		**TOTAL STEAM PRODUCTION**	**1,313,886,483**	**1,416,246,539**	**1,424,453,389**	**1,432,634,133**	**1,436,041,457**	**1,444,295,126**	**1,449,250,337**	**1,455,546,300**	**1,462,760,256**
		OTHER PRODUCTION									
10	341	Structures & Improvmnts	7,538,380	8,368,936	8,438,710	8,508,484	8,578,302	8,648,120	8,713,415	8,783,823	8,854,230
11	344	Generators	18,885,909	20,889,158	21,057,172	21,225,189	21,393,206	21,561,224	21,729,241	21,898,659	22,068,076
12	345	Accessory Electric Equip	1,513,362	1,456,561	1,460,737	1,430,638	1,448,476	1,466,316	1,483,556	1,501,620	1,519,685
13	346	34600 - Misc Power Plant Equip	84,189	102,704	104,282	105,860	107,439	109,017	110,600	112,222	113,843
14		**TOTAL OTHER PRODUCTION**	**28,021,840**	**30,817,359**	**31,060,901**	**31,270,171**	**31,527,423**	**31,784,678**	**32,036,812**	**32,296,323**	**32,555,834**
		TRANSMISSION PLANT									
15	350	Land & Land Rights	25,215,796	26,488,259	26,596,165	26,704,083	26,812,013	26,920,764	27,029,652	27,142,065	27,254,614
16	352	Structures and Improvements	5,470,668	5,592,079	5,609,361	5,626,665	5,643,072	5,660,788	5,672,331	5,580,825	5,599,868
17	353	Station Equipment	171,682,820	169,127,994	169,482,734	170,238,868	170,847,294	171,469,131	171,773,022	171,731,091	172,198,877
18	35316			297	1,264	2,250	3,481	4,491	5,552	6,921	8,786
19	354	Towers and Fixtures	26,977,543	27,519,914	27,590,615	27,598,655	27,669,653	27,740,652	27,811,651	27,882,828	27,954,013
20	355	Poles and Fixtures	143,700,332	155,757,810	157,059,152	157,207,876	158,712,206	160,210,295	160,163,816	160,807,825	162,394,057
21	356	Overhead Conductors, Device	116,913,990	122,611,652	123,226,759	123,847,507	124,412,702	124,936,587	125,297,707	125,271,097	125,200,848
22	35616	OVH Cond-Dev-Smart Grid		7,428	9,371	15,580	22,621	33,562	44,629	62,318	81,780
23	357	Underground Conduit	2,592	2,960	3,065	4,337	5,794	7,475	9,164	11,021	12,970
24	358	Undergrnd Conductors Device	115	123	123	124	124	125	126	126	127
25	35816	Ug Cond-Dev-Smart Grid		32	47	103	164	233	302	374	450
26	359	Roads and Trails	92,311	94,056	94,202	94,348	94,495	94,641	94,787	94,933	95,080
27		**TOTAL TRANSMISSION PLAN**	**490,056,167**	**507,202,601**	**509,672,857**	**511,340,398**	**514,223,621**	**517,078,744**	**517,902,739**	**518,591,426**	**520,801,469**
		DISTRIBUTION PLANT									
28	360	Land & Land Rights	2,288,811	2,336,096	2,340,138	2,344,179	2,348,221	2,352,383	2,356,545	2,360,707	2,364,869
29	361	Structures and Improvements	2,233,335	2,313,422	2,320,259	2,328,281	2,336,489	2,344,540	2,352,592	2,360,673	2,368,169
30	362	Station Equipment	83,296,434	85,799,979	85,715,301	86,131,658	86,633,914	86,392,545	86,818,729	87,000,960	87,600,702
31	36216	Station Equipment-SmartGrid			163	335	509	692	875	1,102	1,447
32	364	Poles, Towers and Fixtures	186,320,694	189,573,879	189,696,834	190,173,794	190,807,806	191,266,086	191,691,715	192,233,793	192,595,532
33	365	Overhead Conductors, Device	145,375,072	151,681,982	152,045,143	152,488,304	153,209,397	153,931,381	154,501,381	155,088,017	155,564,329
34	366	Underground Conduit	23,358,246	24,666,595	24,778,542	24,881,647	24,994,200	25,101,755	25,209,627	25,316,723	25,427,118
35	367	Undergrnd Conductors,Device	91,803,531	96,381,442	96,802,258	97,209,006	97,633,831	97,965,656	98,336,857	98,724,317	99,104,210
36	368	Line Transformers	126,343,524	121,142,340	121,251,280	121,256,540	121,345,905	121,205,974	120,536,175	119,893,970	119,770,247
37	369	Services	35,342,004	37,822,050	38,049,518	38,236,361	38,414,820	38,681,301	38,950,029	39,123,691	39,392,503
38	370	Meters	(42,394,301)	(41,076,565)	(40,999,060)	(40,862,311)	(40,714,475)	(40,604,364)	(40,545,620)	(40,451,256)	(40,265,725)
39	371	Installs Customer Premises	24,379,397	24,751,962	24,820,313	24,912,508	24,965,576	25,062,658	25,163,834	25,206,442	25,268,529

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Schedule E-17 Part II B

Explanation: Schedule showing the trial balance by detail general ledger subaccount for the test year and two preceding non-overlapping fiscal or calendar years. Also, provide monthly trial balances for the historical portion of the test year.

Line No.	Accoun	Plant	12/31/2016	Historic Balances 12/31/2017	1/31/2018	2/28/2018	3/31/2018	4/30/2018	5/31/2018	6/30/2018	7/31/2018
40	373	Street Lghtng & Signal Sys	24,817,703	25,221,751	25,295,547	25,373,181	25,441,970	25,540,548	25,619,243	25,673,011	25,737,182
41		**TOTAL DISTRIBUTION PLANT**	**703,164,449**	**720,614,932**	**722,116,237**	**724,473,483**	**727,418,164**	**729,241,155**	**730,991,984**	**732,532,149**	**734,929,112**
		GENERAL PLANT									
42	389	Land	(183,471)	(192,917)	(192,917)	(192,917)	(192,917)	(192,917)	(192,917)	(192,917)	(192,917)
43	390	Structures and Improvements	41,226,318	42,770,924	42,284,085	42,473,952	42,663,846	42,793,507	42,983,429	43,159,530	43,038,472
44	391	Office Furniture, Equipment	6,624,095	6,368,962	6,393,599	6,418,237	6,443,129	6,467,766	6,492,404	6,518,849	6,544,553
45	392	Transportation Equipment	3,435,452	3,600,174	3,612,600	3,625,026	3,637,452	3,649,877	3,662,303	3,673,875	3,685,448
46	393	Stores Equipment	2,462,599	1,648,096	1,656,977	1,665,857	1,674,737	1,683,821	1,692,905	1,702,213	1,711,522
47	394	Tools	6,717,419	8,464,101	8,536,370	8,608,887	8,681,995	8,754,721	8,828,966	8,903,866	8,978,984
48	395	Laboratory Equipment	5,260,701	5,421,732	5,425,764	5,429,796	5,433,829	5,437,861	5,441,893	5,445,791	5,449,512
49	396	Power Operated Equipment	75,318	58,726	60,404	57,249	66,625	68,527	69,574	63,935	30,628
50	397	Communication Equipment	21,503,527	16,236,900	16,425,005	16,626,239	16,823,583	17,019,223	17,214,579	17,415,760	17,615,844
51	39716	GridSmart Communic Equip		469	704	3,757	6,920	10,281	12,903	15,602	18,300
52	398	Miscellaneous Equipment	1,182,987	1,196,252	1,208,562	1,220,992	1,233,436	1,245,886	1,258,336	1,271,211	1,284,085
53	399	Other Property - Land	71,687,865	73,243,694	73,372,859	73,529,197	73,835,945	74,031,377	74,147,730	74,358,637	74,556,797
54	39919	ARO General Plant	459,899	546,719	553,354	559,990	566,626	573,262	579,897	581,066	587,702
55		**TOTAL GENERAL PLANT**	**160,452,709**	**159,363,833**	**159,337,367**	**160,026,263**	**160,875,204**	**161,543,191**	**162,192,003**	**162,917,418**	**163,308,930**
		INTANGIBLE PLANT									
56	303	Miscellaneous Intangible Plant	30,989,469	42,327,848	43,651,275	44,994,137	45,771,336	47,151,812	48,551,314	48,587,681	50,016,984
57		**TOTAL INTANGIBLE PLANT**	**30,989,469**	**42,327,848**	**43,651,275**	**44,994,137**	**45,771,336**	**47,151,812**	**48,551,314**	**48,587,681**	**50,016,984**
58		**RWIP**	**(13,703,710)**	**(12,434,633)**	**(11,731,157)**	**(11,896,101)**	**(12,854,032)**	**(13,620,960)**	**(11,599,041)**	**(11,137,085)**	**(12,348,758)**
59		**Total**	**2,712,867,405**	**2,864,138,479**	**2,878,560,869**	**2,892,842,484**	**2,903,003,174**	**2,917,473,745**	**2,929,326,149**	**2,939,334,213**	**2,952,023,828**

Reconciliation from Schd E 17-B

Account	12/31/2017	1/31/2018	2/28/2018	3/31/2018	4/30/2018	5/31/2018	6/30/2018	7/31/2018
1080001	(2,453,707,900)	(2,465,507,098)	(2,477,202,432)	(2,486,910,998)	(2,499,044,494)	(2,507,488,985)	(2,513,076,184)	(2,523,824,601)
1080005	12,434,633	11,731,157	11,896,101	12,854,032	13,620,960	11,599,041	11,137,085	12,348,758
1080011	(430,814,148)	(431,410,437)	(432,818,799)	(433,451,655)	(435,175,183)	(435,161,674)	(439,084,217)	(440,807,785)
1080155	50,276,784	50,276,784	50,276,784	50,276,784	50,276,784	50,276,784	50,276,784	50,276,784
1110001	(42,327,848)	(43,651,275)	(44,994,137)	(45,771,336)	(47,151,812)	(48,551,314)	(48,587,681)	(50,016,984)
	(2,864,138,479)	(2,878,560,869)	(2,892,842,484)	(2,903,003,174)	(2,917,473,745)	(2,929,326,149)	(2,939,334,213)	(2,952,023,828)

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Line			Forcasted Balances					
No.	Accoun	Plant	8/31/2018	9/30/2018	10/31/2018	11/30/2018	12/31/2018	12/31/2019
		PRODUCTION PLANT						
		STEAM PRODUCTION						
1	310	Land	9,535	9,535	9,535	9,535	9,535	9,535
2	311	Structures & Improvmnts	271,471,913	272,801,373	274,144,839	275,534,885	275,892,313	291,496,876
3	312	Boiler Plant Equip	794,332,730	798,306,550	802,322,225	806,477,138	807,545,503	854,188,247
4	314	Turbogenerator Units	237,783,386	238,954,609	240,138,168	241,362,768	241,677,653	255,424,905
5	315	Accessory Elect Equip	72,388,004	72,749,658	73,115,124	73,493,261	73,590,494	77,835,425
6	316	Misc Pwr Plant Equip	79,692,163	80,077,239	80,466,368	80,868,988	80,972,515	85,492,325
7	31700	ARO Steam Production Plant	7,470,425	7,506,276	7,542,502	7,579,987	7,589,627	8,010,416
8	31730	ARO Steam Production Plant Oi	2,962,210	2,976,424	2,990,790	3,005,654	3,009,475	3,176,328
9		**TOTAL STEAM PRODUCTION**	**1,466,110,366**	**1,473,381,664**	**1,480,729,551**	**1,488,332,216**	**1,490,287,115**	**1,575,634,057**
		OTHER PRODUCTION						
10	341	Structures & Improvmnts	8,873,850	8,916,435	8,959,469	9,003,994	9,015,443	9,515,285
11	344	Generators	22,116,977	22,223,115	22,330,371	22,441,345	22,469,881	23,715,673
12	345	Accessory Electric Equip	1,523,052	1,530,361	1,537,747	1,545,389	1,547,354	1,633,144
13	346	34600 - Misc Power Plant Equip	114,096	114,643	115,197	115,769	115,916	122,343
14		**TOTAL OTHER PRODUCTION**	**32,627,975**	**32,784,554**	**32,942,784**	**33,106,497**	**33,148,594**	**34,986,445**
		TRANSMISSION PLANT						
15	350	Land & Land Rights	27,315,007	27,446,092	27,578,555	27,715,608	27,750,852	29,289,436
16	352	Structures and Improvements	5,612,276	5,639,210	5,666,425	5,694,588	5,701,827	6,017,951
17	353	Station Equipment	172,580,455	173,408,654	174,245,578	175,111,522	175,334,186	185,055,202
18	35316		8,805	8,847	8,889	8,934	8,946	9,441
19	354	Towers and Fixtures	28,015,956	28,150,402	28,286,265	28,426,839	28,462,985	30,041,054
20	355	Poles and Fixtures	162,753,908	163,534,953	164,324,223	165,140,860	165,350,847	174,518,358
21	356	Overhead Conductors, Device	125,478,283	126,080,442	126,688,946	127,318,550	127,480,441	134,548,311
22	35616	OVH Cond-Dev-Smart Grid	81,961	82,355	82,752	83,161	83,269	87,885
23	357	Underground Conduit	12,999	13,062	13,124	13,189	13,206	13,939
24	358	Undergrnd Conductors Device	127	128	128	129	129	136
25	35816	Ug Cond-Dev-Smart Grid	450	452	454	458	458	484
26	359	Roads and Trails	95,290	95,748	96,210	96,688	96,811	102,179
27		**TOTAL TRANSMISSION PLAN**	**521,955,517**	**524,460,345**	**526,991,549**	**529,610,526**	**530,283,957**	**559,684,376**
		DISTRIBUTION PLANT						
28	360	Land & Land Rights	2,370,109	2,381,484	2,392,977	2,404,870	2,407,928	2,541,429
29	361	Structures and Improvements	2,373,418	2,384,808	2,396,317	2,408,226	2,411,288	2,544,977
30	362	Station Equipment	87,794,817	88,216,138	88,641,896	89,082,418	89,195,691	94,140,948
31	36216	Station Equipment-SmartGrid	1,450	1,458	1,464	1,472	1,474	1,556
32	364	Poles, Towers and Fixtures	193,022,307	193,948,607	194,884,663	195,853,176	196,102,213	206,974,666
33	365	Overhead Conductors, Device	155,909,045	156,657,243	157,413,318	158,195,611	158,396,764	167,178,724
34	366	Underground Conduit	25,483,462	25,605,755	25,729,337	25,857,203	25,890,081	27,325,500
35	367	Undergrnd Conductors,Device	99,323,817	99,800,464	100,282,132	100,780,501	100,908,648	106,503,306
36	368	Line Transformers	120,035,647	120,611,690	121,193,799	121,796,092	121,950,963	128,712,264
37	369	Services	39,479,794	39,669,255	39,860,710	40,058,805	40,109,742	42,333,538
38	370	Meters	(40,354,950)	(40,548,611)	(40,744,311)	(40,946,798)	(40,998,863)	(43,271,954)
39	371	Installs Customer Premises	25,324,521	25,446,052	25,568,862	25,695,932	25,728,605	27,155,070

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Line No.	Accoun	Plant	Forcasted Balances 8/31/2018	9/30/2018	10/31/2018	11/30/2018	12/31/2018	12/31/2019
40	373	Street Lghtng & Signal Sys	25,794,214	25,917,997	26,043,086	26,172,512	26,205,792	27,658,713
41		**TOTAL DISTRIBUTION PLANT**	**736,557,651**	**740,092,340**	**743,664,250**	**747,360,020**	**748,310,326**	**789,798,737**
		GENERAL PLANT						
42	389	Land	(193,344)	(194,272)	(195,209)	(196,180)	(196,429)	(207,320)
43	390	Structures and Improvements	43,133,839	43,340,839	43,550,014	43,766,445	43,822,095	46,251,713
44	391	Office Furniture, Equipment	6,553,729	6,573,644	6,593,769	6,614,592	6,619,946	6,853,701
45	392	Transportation Equipment	3,693,599	3,711,287	3,729,162	3,747,655	3,752,412	3,960,030
46	393	Stores Equipment	1,715,313	1,723,546	1,731,865	1,740,471	1,742,683	1,839,302
47	394	Tools	8,998,883	9,042,066	9,085,707	9,130,858	9,142,467	9,649,353
48	395	Laboratory Equipment	5,453,080	5,460,824	5,468,650	5,476,746	5,478,829	5,569,723
49	396	Power Operated Equipment	30,696	30,843	30,991	31,145	31,186	32,915
50	397	Communication Equipment	17,652,710	17,732,728	17,813,589	17,897,251	17,918,764	18,857,971
51	39716	GridSmart Communic Equip	18,341	18,429	18,518	18,610	18,634	19,667
52	398	Miscellaneous Equipment	1,286,842	1,292,825	1,298,869	1,305,125	1,306,733	1,376,953
53	399	Other Property - Land	74,714,153	75,055,690	75,400,822	75,757,922	75,849,745	79,858,525
54	39919	ARO General Plant	588,999	591,812	594,655	597,597	598,354	631,379
55		**TOTAL GENERAL PLANT**	**163,646,840**	**164,380,261**	**165,121,402**	**165,888,237**	**166,085,419**	**174,693,912**
		INTANGIBLE PLANT						
56	303	Miscellaneous Intangible Plant	50,123,371	50,386,820	50,652,903	50,922,301	50,972,631	53,806,366
57		**TOTAL INTANGIBLE PLANT**	**50,123,371**	**50,386,820**	**50,652,903**	**50,922,301**	**50,972,631**	**53,806,366**
58		**RWIP**	**(12,375,024)**	**(12,440,067)**	**(12,505,761)**	**(12,572,273)**	**(12,584,699)**	**(13,284,323)**
59		**Total**	**2,958,646,696**	**2,973,045,917**	**2,987,596,678**	**3,002,647,524**	**3,006,503,343**	**3,175,319,570**

(2,529,192,798)	(2,542,486,297)	(2,555,912,643)	(2,569,506,283)	(2,572,045,913)	(2,715,034,354)
12,375,024	12,440,067	12,505,761	12,572,273	12,584,699	13,284,323
(441,982,335)	(442,889,651)	(443,813,677)	(445,067,997)	(446,346,282)	(470,039,957)
50,276,784	50,276,784	50,276,784	50,276,784	50,276,784	50,276,784
(50,123,371)	(50,386,820)	(50,652,903)	(50,922,301)	(50,972,631)	(53,806,366)
(2,958,646,696)	(2,973,045,917)	(2,987,596,678)	(3,002,647,524)	(3,006,503,343)	(3,175,319,570)

Southerwestern Electric Power Company
INDEX- AEP, Inc. E Workpapers
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Southerwestern Electric Power Company
Balance Sheet - AEP, Inc.
Test Year Ending December 31, 2018
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SCHEDULE E-1 HC

Line No.	Account Number	Description	Historical Test Year Amount (A)	Account Number	Description	Historical Test Year Amount (A)
		Current Assets			**Current Liabilities**	
1	1310000, 1350000,1360000, 1840000	Cash and cash equivalents	102,303,386	2310000	Short-term Debt	1,755,000,000
2	1430000, 1460000, 1710002	Accounts receivable customers	105,190,761	2240000	Other Long-term Debt	(738,112)
3	1320000, 1340000	Special Deposits	1,346,851	232,234	Accounts Payable	2,757,340
4	1450000	Prepayments	2,296,261	233	Advances from Affiliates	462,905,535
5	1450000	Advances to Affiliates	1,140,130,039	245	Current Risk Mgmt	738,112
6		**Total Current Assets**	**1,351,267,297**	223805	Accrued taxes	29,564,623
7				237	Accrued interest	7,232,335
8	1010000, 1060000	Gross Property, Plant & Equip	1,976,983	242	Other	5,686,587
9		**Total property, plant and equipment**	**1,976,983**			-
10	1070000	Construction work in progress	5,336		**Total Current Liabilities**	**2,263,146,420**
11		**Total Gross Plant**	**1,982,319**			
12	110800,111100	Less accumulated depreciation	(1,021,933)	224,181,226	Long-Term Debt	1,264,472,644
13		**Total Net Plant**	**960,386**	245	Long-Term Risk Mgmt	27,226,313
14	2540000	Regulatory Assets	(5,363,702)		**Deferred Credits and Other Liabilities**	
15	1230000, 1230001	Investments in Power & Distr Prj	21,081,572,065	228	Accrued pension and benefit obligations	25,624,141
16	1231007	Goodwill	37,060,693	236,282,283	Accumulated deferred income taxes	(26,778,625)
17	1240001, 1860000	Other Non-Current Assets	51,890,669	236,237,211,253	Other	31,498,193
18					**Total Deferred Credits and Other Liabiliti**	**30,343,709**
19		**Total Assets**	**22,517,387,408**			.
20					**Stockholders' Equity**	
21				201	Common stockholders' equity	3,335,426,513
22				219	Accumulated other comprehensive income	1,791,474
23				207,210,211,214	Paid In Capital	6,423,816,695
				215	Retained Earnings	9,171,163,641
24					**Total Stockholders' Equity**	**18,932,198,323**
25						
26					**Total Liabilities and Stockholders' Equity**	**22,517,387,408**

Recap Schedules
(C) Schedule D-1.2 HC

Southerwestern Electric Power Company
Income Statement - AEP, Inc.
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SCHEDULE E-2 HC

Line No.	Account Number	Description	Amount
			(a)
1	4510003	Misc Service Rev - Affiliated	7,402,612
2	4210000	Misc Non-Operating Income	1,440,089
3		**Total Operating Revenues**	**8,842,701**
4		**Operating Expenses**	
5	5000000	Oper Supervison & Engineering	781
6	5660000	Misc Transmission Expenses	741
7	5880000	Miscellaneous Distribution Exp	1,796
8	9100000	Misc Cust Svc&Informational Ex	603
9		**Administration & General**	
10	9200000	Administrative & Gen Salaries	1,290,970
11	9210001	Off Supl & Exp - Nonassociated	877,926
12	9230001	Outside Svcs Empl - Nonassoc	(5,241,783)
13	9230003	AEPSC Billed to Client Co	7,258,766
14	9250000	Injury and Damages	1,350,260
15	9280000	Regulatory Commission Exp	6,858
16	9301000	General Advertising Expenses	16,820,973
17	9302000	Misc General Expenses	5,528,773
18	9310000	Rents	58,656
19	4264000	Civic and Political Activity	220,298
20	4264001	Non-deduct Lobbying per IRS	1,418
21	4265002	Other Deductions - nonassoc	9,303,750
22		**Operational Expenses**	**37,480,786**
23	935	Maintenance of General Plant	738
24		**Total Operational and Maintenance Expenses**	**37,481,525**
25	4040001	Amort of Plant	190,861
26	4081006	State Gross Receipts Tax	1,980
27		**TOTAL OPERATING EXPENSES**	**37,674,365**
28		**OPERATING INCOME**	**(28,831,664)**
29		**NON-OPERATING INCOME/(EXPENSES)**	
30	4190002	Int & Dividend Inc - Nonassoc	1,607,443
31	4190001	Interest Inc - Assoc Non CBP	1,950,332
32	4190005	Interest Inc - Assoc CBP	30,707,865
33		**Total Interest & Dividend Income**	**34,265,640**
34	4270006	Interest on LTD - Sen Unsec Notes	41,616,562
35	4300003	Interest to Assoc Co - CBP (Money Pool)	10,363,865
36	4310005	Commercial Paper	38,864,388
37	4310007	Lines of Credit	610,728
38	4280001	Amort of Debt Disc Prem & Exp	1,903,265
39	4210013	Int Rate Hedge Unrealized Gain	(21,571,227)
40	4265011	Int Rate Hedge Unrealized Loss	21,810,577
41		**Total Interest Charges**	**93,598,158**
42		**INCOME BEFORE INCOME TAXES and EQUITY EARNING**	**(88,164,182)**
43		**INCOME TAXES and EQUITY EARNINGS**	
44	4091001	Income Taxes, UOI - Federal	823,588
45	4092001	Inc Tax, Oth Inc&Ded-Federal	2,693,395
46	4101001	Prov Def I/T Util Op Inc-Fed	2,985,090
47	4102001	Prov Def I/T Oth I&D - Federal	4,102
48	4111001	Prv Def I/T-Cr Util Op Inc-Fed	(1,538,054)
49		**Federal Income Taxes**	**4,968,121**
50		**Total Income Taxes**	**4,968,121**
51	4181001	Equity Erngs of Sub-Consolidat	2,008,791,098
52		**Equity Earnings of Subs**	**2,008,791,098**
53		**INCOME AFTER INCOME TAXES and EQUITY EARNINGS**	**1,915,658,792**
54		**NET INCOME from E-17A HC**	**1,915,658,792**

Supporting Schedules and Workpapers:
(a) Schedule C-3
(b) Schedule E-3
(c) Schedule E-17A HC

Southerwestern Electric Power Company
Income Statement - AEP, Inc.
Test Year Ending December 31, 2018
Docket No. 19-008-U

100 - American Electric Power Co.
INCOME STATEMENT

Schedule E-17A HC

Jul 2018 Layout: GAAP_IS1
17A V2018-07-31 Account: GL_ACCT_SEC Business Unit: 100

		YTD Dec 2016	YTD Dec 2017	Actual Jan MTD 2018	Actual Feb MTD 2018	Actual Mar MTD 2018	Actual Apr MTD 2018	Actual May MTD 2018	Actual Jun MTD 2018	Actual Jul MTD 2018
	REVENUES									
4560016	Financial Trading Rev-Unreal		-	-	-	-	-	-	-	-
	Revenue - Resale-NonAffiliated	-	-	-	-	-	-	-	-	-
			-							
4510003	Misc Service Rev - Affiliated	9,697,756	9,081,553	682,157	738,426	733,417	1,045,395	811,615	742,577	648,655
	Revenue - Other Ele-Affilliated	**9,697,756**	**9,081,553**	**682,157**	**738,426**	**733,417**	**1,045,395**	**811,615**	**742,577**	**648,655**
	Revenue - Other Opr Electric	**9,697,756**	**9,081,553**	**682,157**	**738,426**	**733,417**	**1,045,395**	**811,615**	**742,577**	**648,655**
4210000	Misc Non-Operating Income	7,959	1,133	-	-	33	-	-	-	-
4210007	Misc Non-Op Inc - NonAsc - Oth	2,784,110	5,947,963	-	-	391,115	-	-	370,381	-
	Revenue - Other Opr - Other	**2,792,069**	**5,949,096**	**-**	**-**	**391,148**	**-**	**-**	**370,381**	**-**
	Revenue - Other Operating	**12,489,825**	**15,030,649**	**682,157**	**738,426**	**1,124,565**	**1,045,395**	**811,615**	**1,112,958**	**648,655**
	TOTAL OPERATING REVENUES	**12,489,825**	**15,030,649**	**682,157**	**738,426**	**1,124,565**	**1,045,395**	**811,615**	**1,112,958**	**648,655**
			-							
			-							
	OPERATING EXPENSES		-							
			-							
5000000	Oper Supervision & Engineering		1,455	973	(191)	-	-	-	-	-
5060000	Misc Steam Power Expenses		38,078	-	-	-	-	-	-	-
	Steam Generation Op Exp	**-**	**39,534**	**973**	**(191)**	**-**	**-**	**-**	**-**	**-**
5240000	Misc Nuclear Power Expenses		4	0	0	0	0	0	-	1
	Nuclear Generation Op Exp	**-**	**4**	**0**	**0**	**0**	**0**	**0**	**-**	**1**
5600000	Oper Supervision & Engineering		-	-	-	-	-	-	-	-
5660000	Misc Transmission Expenses		299	-	-	739	2	-	-	-
	Transmission Op Exp	**-**	**299**	**-**	**-**	**739**	**2**	**-**	**-**	**-**
5800000	Oper Supervision & Engineering	60	-	-	-	-	-	-	-	-
5880000	Miscellaneous Distribution Exp		337	-	-	1,796	-	-	-	-
	Distribution Op Exp	**60**	**337**	**-**	**-**	**1,796**	**-**	**-**	**-**	**-**
9080000	Customer Assistance Expenses	645	-	-	-	-	-	-	-	-
9100000	Misc Cust Svc&Informational Ex		-	-	-	-	-	-	603	-
	Customer Service and Information Op Exp	**645**	**-**	**-**	**-**	**-**	**-**	**-**	**603**	**-**
9200000	Administrative & Gen Salaries	48,931	30,032	(5)	3,026	53,438	15,903	1,249,007	2,104	38,824
9210001	Off Supl & Exp - Nonassociated	642,326	1,707,156	16,796	11,379	90,638	64,371	403,272	22,432	25,253
9230001	Outside Svcs Empl - Nonassoc	4,889,363	1,816,998	127,182	103,989	149,099	187,204	127,724	150,869	128,090
9230003	AEPSC Billed to Client Co	12,101,726	9,085,465	639,548	894,998	520,492	483,452	638,376	442,802	606,508
9240000	Property Insurance	84								
9250000	Injuries and Damages	1,077,812	769,005	1,231	1,327	1,725	1,327	2,837	7,277	1,327
9250004	Injuries to Employees		-	-	-	-	-	1,325,000	-	-
9260027	Savings Plan Contributions	224	-	-	-	-	-	-	-	-
9280002	Regulatory Commission Exp-Case		-	-	-	-	-	-	-	6,858
9301000	General Advertising Expenses	14,626,647	11,973,617	191,685	296,157	318,869	2,747,262	2,044,287	2,588,536	1,595,054
9302000	Misc General Expenses	5,545,282	7,971,177	6,814	4,127	(1,552,347)	3,393	10,941	964,867	15
9302003	Corporate & Fiscal Expenses	2,359,836	2,193,549	193,221	175,985	118,045	830,275	201,855	159,695	139,822
9302004	Research, Develop&Demonstr Exp	270	35	-	-	60	-	11	-	-
9310002	Rents - Personal Property	100,322	100,322	8,333	8,333	8,333	8,656	8,333	8,333	8,333
	Administration & General	**41,392,824**	**35,647,357**	**1,184,806**	**1,499,320**	**(291,651)**	**4,341,843**	**6,011,643**	**4,346,916**	**2,550,084**
4211000	Gain on Dspsition of Property	2,484,020	-	-	-	-	-	-	-	-
	Loss(Gain) of Sale of Property	**2,484,020**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
4250000	Miscellaneous Amortization		(22)	-	-	-	-	-	-	-
	Expense of Non-Utility Operation	**-**	**(22)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
4261000	Donations	147,682	113	-	-	-	-	-	-	-
	Donation Contributions	**147,682**	**113**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Provision for Penalties		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
4264000	Civic and Political Activity	181,860	164,790	1,255	8,997	57,463	23,204	19,755	106,934	2,690
4264001	Non-deduct Lobbying per IRS		-	-	-	-	-	1,418	-	-
	Civic & Political Activities	**181,860**	**164,790**	**1,255**	**8,997**	**57,463**	**23,204**	**21,173**	**106,934**	**2,690**
4265002	Other Deductions - Nonassoc		-	-	1,910	9,235,750	-	66,090	-	-
4265033	Transition Costs	3,062	88,684	-	-	-	-	-	-	-
4265034	Transaction Costs	335,707								
	Other Deductions	**338,769**	**88,684**	**-**	**1,910**	**9,235,750**	**-**	**66,090**	**-**	**-**
	All Other Operational Expenses	**668,311**	**253,565**	**1,255**	**10,907**	**9,293,213**	**23,204**	**87,263**	**106,934**	**2,690**
	Operational Expenses	**44,545,859**	**35,941,095**	**1,187,034**	**1,510,036**	**9,004,097**	**4,365,050**	**6,098,907**	**4,454,453**	**2,552,775**

Southerwestern Electric Power Company
Income Statement - AEP, Inc.
Test Year Ending December 31, 2018
Docket No. 19-008-U

100 - American Electric Power Co.
INCOME STATEMENT

Schedule E-17A HC

Jul 2018 Layout: GAAP_IS1
17A V2018-07-31 Account: GL_ACCT_SEC Business Unit: 100

Account	Description	YTD Dec 2016	YTD Dec 2017	Actual Jan MTD 2018	Actual Feb MTD 2018	Actual Mar MTD 2018	Actual Apr MTD 2018	Actual May MTD 2018	Actual Jun MTD 2018	Actual Jul MTD 2018
			-							
5320000	Maint of Misc Nuclear Plant		(58)	-	-	-	-	-	-	-
	Nuclear Generation Maintenance	**-**	**(58)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
9350013	Maint of Cmmncation Eq-Unall	-	1,420	623	-	115	-	-	-	-
	Administration & General Maintenance	**-**	**1,420**	**623**	**-**	**115**	**-**	**-**	**-**	**-**
	Maintenance Expenses	**-**	**1,363**	**623**	**-**	**115**	**-**	**-**	**-**	**-**
	Total Maintenance and Operational Expenses	**44,545,859**	**35,942,458**	**1,187,657**	**1,510,036**	**9,004,212**	**4,365,050**	**6,098,907**	**4,454,453**	**2,552,775**
			-							
			-							
4040001	Amort. of Plant	165,088	257,613	26,599	26,911	27,073	27,286	27,426	27,682	27,883
	Depreciation and Amortization	**165,088**	**257,613**	**26,599**	**26,911**	**27,073**	**27,286**	**27,426**	**27,682**	**27,883**
			-							
408100812	State Franchise Taxes	(21,678)								
408100814	State Franchise Taxes		(1,575)	-	-	-	-	-	-	-
408100816	State Franchise Taxes		25	-	-	-	-	-	-	-
408100817	State Franchise Taxes		25	-	-	-	-	-	-	-
	Franchise Taxes	**(21,678)**	**(1,525)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
408100616	State Gross Receipts Tax	5,638	1,621	-	-	-	-	-	-	-
408100617	State Gross Receipts Tax		14,505	-	963	-	-	-	-	-
408100618	State Gross Receipts Tax		-	-	-	-	-	1,017	-	-
	Revenue-kWhr Taxes	**5,638**	**16,126**	**-**	**963**	**-**	**-**	**1,017**	**-**	**-**
408102714	Misc State and Local Taxes		-	-	-	-	-	-	-	-
408102715	Misc State and Local Taxes	25	-	-	-	-	-	-	-	-
408201615	Misc State and Local Taxes		-	-	-	-	-	-	-	-
408201617	Misc State and Local Taxes		9	-	-	-	-	-	-	-
	Other Non-Income Taxes	**25**	**9**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Taxes Other Than Income Taxes	**(16,015)**	**14,610**	**-**	**963**	**-**	**-**	**1,017**	**-**	**-**
	TOTAL OPERATING EXPENSES	**44,694,932**	**36,214,681**	**1,214,255**	**1,537,911**	**9,031,286**	**4,392,336**	**6,127,350**	**4,482,135**	**2,580,658**
			-							
	OPERATING INCOME	**(32,205,107)**	**(21,184,032)**	**(532,098)**	**(799,485)**	**(7,906,721)**	**(3,346,941)**	**(5,315,735)**	**(3,369,177)**	**(1,932,003)**
			-							
	NON-OPERATING INCOME / (EXPENSES)		-							
			-							
4190002	Int & Dividend Inc - Nonassoc	389,261	2,627,672	113,911	120,041	190,027	159,187	122,779	636,085	168,652
	Interest & Dividend NonAffiliated	**389,261**	**2,627,672**	**113,911**	**120,041**	**190,027**	**159,187**	**122,779**	**636,085**	**168,652**
4190001	Interest Inc - Assoc Non CBP	904,000	1,639,122	158,917	158,917	158,917	158,917	158,917	158,917	158,917
4190005	Interest Income - Assoc CBP	10,017,781	16,199,400	1,755,951	1,753,161	3,491,158	3,819,699	3,306,555	2,657,183	2,711,704
	Interest & Dividend Affiliated	**10,921,781**	**17,838,523**	**1,914,868**	**1,912,077**	**3,650,075**	**3,978,615**	**3,465,472**	**2,816,100**	**2,870,621**
	Total Interest & Dividend Income	**11,311,042**	**20,466,194**	**2,028,779**	**2,032,118**	**3,840,102**	**4,137,802**	**3,588,251**	**3,452,185**	**3,039,273**
			-							
4270006	Int on LTD - Sen Unsec Notes	(17,027,288)	(22,423,612)	(2,625,193)	(2,621,389)	(2,807,611)	(2,763,048)	(2,936,201)	(2,985,087)	(3,030,824)
	Interest on Long-Term Debt	**(17,027,288)**	**(22,423,612)**	**(2,625,193)**	**(2,621,389)**	**(2,807,611)**	**(2,763,048)**	**(2,936,201)**	**(2,985,087)**	**(3,030,824)**
4300003	Int to Assoc Co - CBP	(1,738,782)	(8,257,531)	(737,336)	(708,525)	(913,964)	(1,083,285)	(1,005,113)	(941,922)	(1,043,494)
	Interest STD - Affil	**(1,738,782)**	**(8,257,531)**	**(737,336)**	**(708,525)**	**(913,964)**	**(1,083,285)**	**(1,005,113)**	**(941,922)**	**(1,043,494)**
4310006	Commercial Paper	(6,427,117)	(10,630,272)	(1,508,142)	(1,714,256)	(3,749,029)	(3,908,830)	(3,550,691)	(3,467,822)	(3,693,737)
4310007	Lines Of Credit	(413,844)	(682,629)	(86,150)	(74,984)	(71,032)	(79,777)	(106,869)	(88,109)	(103,807)
	Interest STD - NonAffil	**(6,840,961)**	**(11,312,901)**	**(1,594,292)**	**(1,789,240)**	**(3,820,061)**	**(3,988,607)**	**(3,657,560)**	**(3,555,930)**	**(3,797,544)**
	Interest on Short Term Debt	**(8,579,743)**	**(19,570,432)**	**(2,331,628)**	**(2,497,765)**	**(4,734,025)**	**(5,071,892)**	**(4,662,673)**	**(4,497,853)**	**(4,841,038)**
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	(1,169,191)	(1,333,696)	(143,740)	(145,221)	(155,986)	(155,986)	(155,986)	(155,986)	(155,986)
	Amort of Debt Disc. Prem & Exp	**(1,169,191)**	**(1,333,696)**	**(143,740)**	**(145,221)**	**(155,986)**	**(155,986)**	**(155,986)**	**(155,986)**	**(155,986)**
4210013	Int Rate Hedge Unrealized Gain	(1,621,548)	5,016,165	-	-	14,229,888	-	-	7,341,339	-
4265011	Int Rate Hedge Unreal Losses	1,611,385	(4,777,798)	-	-	(14,469,238)	-	-	(7,341,339)	-
	Interest Rate Hedge Unrealized (Gain)/Loss	**(10,163)**	**238,367**	**-**	**-**	**(239,350)**	**-**	**-**	**-**	**-**
	Total Interest Charges	**(26,786,385)**	**(43,089,373)**	**(5,100,561)**	**(5,264,375)**	**(7,936,972)**	**(7,990,926)**	**(7,754,860)**	**(7,638,926)**	**(8,027,848)**
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	**(47,680,449)**	**(43,807,211)**	**(3,603,881)**	**(4,031,741)**	**(12,003,591)**	**(7,200,065)**	**(9,482,344)**	**(7,555,918)**	**(6,920,579)**
			-							
	INCOME TAXES and EQUITY EARNINGS		-							
			-							
4091001	Income Taxes, UOI - Federal	(8,009,398)	(33,319,949)	-	-	(82,134)	-	-	3,599,117	-
4092001	Inc Tax, Oth Inc&Ded-Federal	(24,227,453)	(278,223)	-	-	-	-	-	-	-

Southerwestern Electric Power Company
Income Statement - AEP, Inc.
Test Year Ending December 31, 2018
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100 - American Electric Power Co.
INCOME STATEMENT

Schedule E-17A HC

Jul 2018 / 17A V2018-07-31	Layout: GAAP_IS1 / Account: GL_ACCT_SEC Business Unit: 100	YTD Dec 2016	YTD Dec 2017	Actual Jan MTD 2018	Actual Feb MTD 2018	Actual Mar MTD 2018	Actual Apr MTD 2018	Actual May MTD 2018	Actual Jun MTD 2018	Actual Jul MTD 2018
	Federal Current Income Tax	**(32,236,851)**	**(33,598,172)**	**-**	**-**	**(82,134)**	**-**	**-**	**3,599,117**	**-**
4101001	Prov Def I/T Util Op Inc-Fed	29,568,572	54,933,815	1,538,054	-	82,134	-	-	454,555	-
4102001	Prov Def I/T Oth I&D - Federal	557,632	282,446	-	-	-	-	-	4,102	-
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(84,228,997)	(21,177,825)	(1,538,054)	-	-	-	-	-	-
4112001	Prv Def I/T-Cr Oth I&D-Fed	-	(342,406)	-	-	-	-	-	-	-
	Federal Deferred Income Tax	**(54,102,793)**	**33,696,030**	**-**	**-**	**82,134**	**-**	**-**	**458,657**	**-**
	Federal Income Taxes	**(86,339,643)**	**97,858**	**-**	**-**	**-**	**-**	**-**	**4,057,775**	**-**
			-							
409100206	Income Taxes, UOI - State	279,508								
409200215	Inc Tax Oth Inc Ded - State	(1,425,354)								
	State Current Income Tax	**(1,145,846)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Total Income Taxes	**(87,485,490)**	**97,858**	**-**	**-**	**-**	**-**	**-**	**4,057,775**	**-**
4181001	Equity Erngs of Sub-Consolidat	549,264,072	1,958,377,372	208,219,925	113,069,131	154,041,705	89,299,544	216,486,957	237,621,529	206,362,646
	Equity Earnings of Subs	**549,264,072**	**1,958,377,372**	**208,219,925**	**113,069,131**	**154,041,705**	**89,299,544**	**216,486,957**	**237,621,529**	**206,362,646**
	INCOME AFTER INCOME TAXES and EQUITY EARNINGS	**589,069,112**	**1,914,472,303**	**204,616,044**	**109,037,390**	**142,038,114**	**82,099,479**	**207,004,613**	**226,007,836**	**199,442,067**
			-							
	NET INCOME	**589,069,112**	**1,914,472,303**	**204,616,044**	**109,037,390**	**142,038,114**	**82,099,479**	**207,004,613**	**226,007,836**	**199,442,067**

Southerwestern Electric Power Company
Income Statement - AEP, Inc.
Test Year Ending December 31, 2018
Docket No. 19-008-U

Jul 2018 Layout: GAAP_IS1
17A V2018-07-31 Account: GL_ACCT_SEC Business Unit: 100

Account	Description	Budget Aug MTD 2018	Budget Sep MTD 2018	Budget Oct MTD 2018	Budget Nov MTD 2018	Budget Dec MTD 2018
	REVENUES					
4560016	Financial Trading Rev-Unreal					
	Revenue - Resale-NonAffiliated	-	-	-	-	-
4510003	Misc Service Rev - Affiliated	400,074	400,074	400,074	400,074	400,074
	Revenue - Other Ele-Affilliated	400,074	400,074	400,074	400,074	400,074
	Revenue - Other Opr Electric	400,074	400,074	400,074	400,074	400,074
4210000	Misc Non-Operating Income					
4210007	Misc Non-Op Inc - NonAsc - Oth	-	349,647	-	-	328,913
	Revenue - Other Opr - Other	-	349,647	-	-	328,913
	Revenue - Other Operating	400,074	749,721	400,074	400,074	728,987
	TOTAL OPERATING REVENUES	400,074	749,721	400,074	400,074	728,987
	OPERATING EXPENSES					
5000000	Oper Supervision & Engineering					
5060000	Misc Steam Power Expenses					
	Steam Generation Op Exp	-	-	-	-	-
5240000	Misc Nuclear Power Expenses					
	Nuclear Generation Op Exp	-	-	-	-	-
5600000	Oper Supervision & Engineering					
5660000	Misc Transmission Expenses					
	Transmission Op Exp	-	-	-	-	-
5800000	Oper Supervision & Engineering					
5880000	Miscellaneous Distribution Exp					
	Distribution Op Exp	-	-	-	-	-
9080000	Customer Assistance Expenses					
9100000	Misc Cust Svc&Informational Ex					
	Customer Service and Information Op Exp	-	-	-	-	-
9200000	Administrative & Gen Salaries	(14,265)	(14,265)	(14,265)	(14,265)	(14,265)
9210001	Off Supl & Exp - Nonassociated	48,757	48,757	48,757	48,757	48,757
9230001	Outside Svcs Empl - Nonassoc	(1,209,485)	(1,251,766)	(1,251,157)	(1,251,766)	(1,251,766)
9230003	AEPSC Billed to Client Co	603,302	603,215	610,382	608,711	606,977
9240000	Property Insurance					
9250000	Injuries and Damages	46	46	8,028	46	46
9250004	Injuries to Employees					
9260027	Savings Plan Contributions					
9280002	Regulatory Commission Exp-Case					
9301000	General Advertising Expenses	1,407,825	1,407,825	1,407,825	1,407,825	1,407,825
9302000	Misc General Expenses	839,581	868,606	851,843	867,971	843,995
9302003	Corporate & Fiscal Expenses					
9302004	Research, Develop&Demonstr Exp					
9310002	Rents - Personal Property					
	Administration & General	1,675,761	1,662,418	1,661,412	1,667,278	1,641,568
4211000	Gain on Dspsition of Property					
	Loss(Gain) of Sale of Property	-	-	-	-	-
4250000	Miscellaneous Amortization					
	Expense of Non-Utility Operation	-	-	-	-	-
4261000	Donations					
	Donation Contributions	-	-	-	-	-
	Provision for Penalties					
4264000	Civic and Political Activity					
4264001	Non-deduct Lobbying per IRS					
	Civic & Political Activities	-	-	-	-	-
4265002	Other Deductions - Nonassoc					
4265033	Transition Costs					
4265034	Transaction Costs					
	Other Deductions	-	-	-	-	-
	All Other Operational Expenses	-	-	-	-	-
	Operational Expenses	1,675,761	1,662,418	1,661,412	1,667,278	1,641,568

Southerwestern Electric Power Company
Income Statement - AEP, Inc.
Test Year Ending December 31, 2018
Docket No. 19-008-U

Jul 2018 / 17A V2018-07-31	Layout: GAAP_IS1 / Account: GL_ACCT_SEC Business Unit: 100	Budget Aug MTD 2018	Budget Sep MTD 2018	Budget Oct MTD 2018	Budget Nov MTD 2018	Budget Dec MTD 2018
5320000	Maint of Misc Nuclear Plant					
	Nuclear Generation Maintenance	-	-	-	-	-
9350013	Maint of Cmmncation Eq-Unall					
	Administration & General Maintenance	-	-	-	-	-
	Maintenance Expenses	-	-	-	-	-
	Total Maintenance and Operational Expenses	**1,675,761**	**1,662,418**	**1,661,412**	**1,667,278**	**1,641,568**
4040001	Amort. of Plant					
	Depreciation and Amortization	-	-	-	-	-
408100812	State Franchise Taxes					
408100814	State Franchise Taxes					
408100816	State Franchise Taxes					
408100817	State Franchise Taxes					
	Franchise Taxes	-	-	-	-	-
408100616	State Gross Receipts Tax					
408100617	State Gross Receipts Tax					
408100618	State Gross Receipts Tax					
	Revenue-kWhr Taxes	-	-	-	-	-
408102714	Misc State and Local Taxes					
408102715	Misc State and Local Taxes					
408201615	Misc State and Local Taxes					
408201617	Misc State and Local Taxes					
	Other Non-Income Taxes	-	-	-	-	-
	Taxes Other Than Income Taxes	-	-	-	-	-
	TOTAL OPERATING EXPENSES	**1,675,761**	**1,662,418**	**1,661,412**	**1,667,278**	**1,641,568**
	OPERATING INCOME	**(1,275,687)**	**(912,697)**	**(1,261,338)**	**(1,267,204)**	**(912,582)**
	NON-OPERATING INCOME / (EXPENSES)					
4190002	Int & Dividend Inc - Nonassoc	96,762				
	Interest & Dividend NonAffiliated	**96,762**	-	-	-	-
4190001	Interest Inc - Assoc Non CBP	167,583	167,583	167,583	167,583	167,583
4190005	Interest Income - Assoc CBP	774,713	1,526,009	2,181,192	3,129,856	3,600,684
	Interest & Dividend Affiliated	**942,296**	**1,693,592**	**2,348,775**	**3,297,439**	**3,768,267**
	Total Interest & Dividend Income	**1,039,058**	**1,693,592**	**2,348,775**	**3,297,439**	**3,768,267**
4270006	Int on LTD - Sen Unsec Notes	(2,947,917)	(2,947,917)	(2,947,917)	(6,430,542)	(6,572,917)
	Interest on Long-Term Debt	**(2,947,917)**	**(2,947,917)**	**(2,947,917)**	**(6,430,542)**	**(6,572,917)**
4300003	Int to Assoc Co - CBP	(418,413)	(840,074)	(890,886)	(885,508)	(895,344)
	Interest STD - Affil	**(418,413)**	**(840,074)**	**(890,886)**	**(885,508)**	**(895,344)**
4310006	Commercial Paper	(3,151,689)	(2,742,415)	(3,912,496)	(3,823,243)	(3,642,038)
4310007	Lines Of Credit					
	Interest STD - NonAffil	**(3,151,689)**	**(2,742,415)**	**(3,912,496)**	**(3,823,243)**	**(3,642,038)**
	Interest on Short Term Debt	**(3,570,103)**	**(3,582,489)**	**(4,803,382)**	**(4,708,751)**	**(4,537,382)**
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	(143,542)	(143,542)	(143,542)	(201,875)	(201,875)
	Amort of Debt Disc. Prem & Exp	**(143,542)**	**(143,542)**	**(143,542)**	**(201,875)**	**(201,875)**
4210013	Int Rate Hedge Unrealized Gain					
4265011	Int Rate Hedge Unreal Losses					
	Interest Rate Hedge Unrealized (Gain)/Loss	-	-	-	-	-
	Total Interest Charges	**(6,661,561)**	**(6,673,947)**	**(7,894,841)**	**(11,341,168)**	**(11,312,174)**
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	**(6,898,189)**	**(5,893,052)**	**(6,807,404)**	**(9,310,933)**	**(8,456,488)**
	INCOME TAXES and EQUITY EARNINGS					
4091001	Income Taxes, UOI - Federal	(218,202)	(429,080)	(493,243)	(692,462)	(860,408)
4092001	Inc Tax, Oth Inc&Ded-Federal	218,202	429,080	493,243	692,462	860,408

Schedule E-17A HC

Southerwestern Electric Power Company
Income Statement - AEP, Inc.
Test Year Ending December 31, 2018
Docket No. 19-008-U

Jul 2018 / 17A V2018-07-31	Layout: GAAP_IS1 / Account: GL_ACCT_SEC Business Unit: 100	Budget Aug MTD 2018	Budget Sep MTD 2018	Budget Oct MTD 2018	Budget Nov MTD 2018	Budget Dec MTD 2018
	Federal Current Income Tax					
4101001	Prov Def I/T Util Op Inc-Fed	182,069	182,069	182,069	182,069	182,069
4102001	Prov Def I/T Oth I&D - Federal					
4111001	Prv Def I/T-Cr Util Op Inc-Fed					
4112001	Prv Def I/T-Cr Oth I&D-Fed					
	Federal Deferred Income Tax	**182,069**	**182,069**	**182,069**	**182,069**	**182,069**
	Federal Income Taxes	**182,069**	**182,069**	**182,069**	**182,069**	**182,069**
409100206	Income Taxes, UOI - State					
409200215	Inc Tax Oth Inc Ded - State					
	State Current Income Tax	**-**	**-**	**-**	**-**	**-**
	Total Income Taxes	**182,069**	**182,069**	**182,069**	**182,069**	**182,069**
4181001	Equity Erngs of Sub-Consolidat	232,769,423	182,221,316	113,772,486	118,763,411	136,163,026
	Equity Earnings of Subs	**232,769,423**	**182,221,316**	**113,772,486**	**118,763,411**	**136,163,026**
	INCOME AFTER INCOME TAXES and EQUITY EARNINGS	**225,689,165**	**176,146,195**	**106,783,012**	**109,270,409**	**127,524,469**
	NET INCOME	**225,689,165**	**176,146,195**	**106,783,012**	**109,270,409**	**127,524,469**

Southerwestern Electric Power Company
Balance Sheet - AEP, Inc.
Test Year Ending December 31, 2018
Docket No. 19-008-U

100 - American Electric Power Co.
BALANCE SHEET

Schedule E-17B HC

Jul 2018 Layout: GAAP_BS1
17A V2018-07-31 Account: GL_ACCT_SEC Business Unit: 100

		Year End December Dec YTD 2016	Year End December Dec YTD 2017	Actual Jan YTD 2018	Actual Feb YTD 2018	Actual Mar YTD 2018	Actual Apr YTD 2018	Actual May YTD 2018	Actual Jun YTD 2018	Actual Jul YTD 2018	Budget Aug YTD 2018	Budget Sep YTD 2018	Budget Oct YTD 2018	Budget Nov YTD 2018	Budget Dec YTD 2018	Budget Dec YTD 2019
	ASSETS															
1310000	Cash	125,331,917	61,460,682	51,669,883	40,156,178	27,863,257	6,163,957	5,923,455	27,869,089	6,946,130			3	6	6	18
	Cash Balances	125,331,917	61,460,682	51,669,883	40,156,178	27,863,257	6,163,957	5,923,455	27,869,089	6,946,130	-	-	3	6	6	18
1360000	Temporary Cash Investments	-	70,674,006	70,090,355	70,143,238	95,185,436	105,240,956	95,300,898	95,284,198	95,357,256						
	Temporary Investments	-	70,674,006	70,090,355	70,143,238	95,185,436	105,240,956	95,300,898	95,284,198	95,357,256	-	-	-	-	-	-
	Cash and Cash Equivalents	**125,331,917**	**132,134,689**	**121,760,238**	**110,299,416**	**123,048,694**	**111,404,912**	**101,224,352**	**123,153,287**	**102,303,386**	**-**	**-**	**3**	**6**	**6**	**18**
1330000	Dividend Special Deposits	1,960,096	2,045,551	1,362,850	1,218,189	1,981,026	1,348,208	1,218,812	1,885,946	1,346,851	1,346,851	1,346,851	1,346,851	1,346,851	1,346,851	1,346,851
	Other Cash Deposits	**1,960,096**	**2,045,551**	**1,362,850**	**1,218,189**	**1,981,026**	**1,348,208**	**1,218,812**	**1,885,946**	**1,346,851**	**1,346,851**	**1,346,851**	**1,346,851**	**1,346,851**	**1,346,851**	**1,346,851**
1460001	A/R Assoc Co - InterUnit G/L	2,135,130	2,058,339	4,845,452	4,390,249	16,139,200	4,198,986	8,119,105	85,737,119	27,104,066	27,430,507	27,430,507	27,430,507	27,430,507	27,430,507	27,430,507
1460006	A/R Assoc Co - Intercompany	73,307	300	300	300	10,121	-	1,065	-	34						
1460009	A/R Assoc Co - InterUnit A/P	(331)	27,981	52,072	(8,228)	325	325	325	325	325						
1460037	A/R Assoc-Global Borrowing Int	226,000	393,167	326,083	234,250	393,167	326,083	234,250	393,167	326,083						
1460049	A/R Assoc Co - Dividends Recv	571,764	(3,833,141)	(3,833,141)	(3,833,141)	-	-	-	-	-						
	Associated Companies	3,005,871	(1,353,354)	1,390,766	783,429	16,542,813	4,525,395	8,354,746	86,130,611	27,430,507	27,430,507	27,430,507	27,430,507	27,430,507	27,430,507	27,430,507
1710000	Interest&Dividends Receivable	50,978,251	-	-	-	-	-	-	-	-	(3,417)	58,417	(0)	(3,417)	58,417	138,350
	Misc AR - Interest & Dividend	50,978,251	-	-	-	-	-	-	-	-	(3,417)	58,417	(0)	(3,417)	58,417	138,350
1430101	Other Accounts Rec - Misc	-	890	776,609	296,941	-	-	-	-	130,118						
1430102	AR Peoplesoft Billing - Misc	7,614,323	7,614,323	7,614,323	7,614,323	7,614,323	7,614,323	77,614,323	77,614,323	77,630,136	77,760,253	77,760,253	77,760,253	77,760,253	77,760,253	77,760,253
	Misc AR - Other Revenue	7,614,323	7,615,213	8,390,932	7,911,264	7,614,323	7,614,323	77,614,323	77,614,323	77,760,253	77,760,253	77,760,253	77,760,253	77,760,253	77,760,253	77,760,253
	Miscellaneous A/R	58,592,574	7,615,213	8,390,932	7,911,264	7,614,323	7,614,323	77,614,323	77,614,323	77,760,253	77,756,837	77,818,670	77,760,253	77,756,837	77,818,670	77,898,603
	Miscellaneous Accounts Receivable	61,598,445	6,261,859	9,781,698	8,694,693	24,157,136	12,139,718	85,969,069	163,744,934	105,190,761	105,187,344	105,249,177	105,190,761	105,187,344	105,249,177	105,329,110
	Accounts Receivable	**61,598,445**	**6,261,859**	**9,781,698**	**8,694,693**	**24,157,136**	**12,139,718**	**85,969,069**	**163,744,934**	**105,190,761**	**105,187,344**	**105,249,177**	**105,190,761**	**105,187,344**	**105,249,177**	**105,329,110**
1450000	Corp Borrow Prg (NR-Assoc)	908,161,393	989,512,590	763,955,363	1,494,138,432	1,683,686,526	1,734,605,483	1,248,023,274	1,276,073,673	1,140,130,039	696,371,606	675,321,768	1,174,452,074	1,479,842,810	1,573,740,964	1,500,293,864
	Advances to Affiliates	**908,161,393**	**989,512,590**	**763,955,363**	**1,494,138,432**	**1,683,686,526**	**1,734,605,483**	**1,248,023,274**	**1,276,073,673**	**1,140,130,039**	**696,371,606**	**675,321,768**	**1,174,452,074**	**1,479,842,810**	**1,573,740,964**	**1,500,293,864**
1540001	M&S - Regular	-	-	-	-	4,525,750	4,525,750	4,591,840	4,591,840	4,591,840						
1540026	Prov for Loss Obsolete M&S	-	-	-	-	(4,525,750)	(4,525,750)	(4,591,840)	(4,591,840)	(4,591,840)						
	Material and Supplies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1760517	Deriv-Hdg-Unreal Gn-FV-Int-Cur	-	2,462,531	2,462,531	2,462,531	1,720,789	1,720,789	1,720,789	-	-						
	Energy Trading - Hedge	-	2,462,531	2,462,531	2,462,531	1,720,789	1,720,789	1,720,789	-	-	-	-	-	-	-	-
	Risk Management Contracts - Current	**-**	**2,462,531**	**2,462,531**	**2,462,531**	**1,720,789**	**1,720,789**	**1,720,789**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
1650001	Prepaid Insurance	752,573	19,422	18,190	16,864	15,537	14,210	18,834	11,557	10,230						
1650006	Other Prepayments	3,131,854	1,237,037	1,068,033	899,029	1,105,025	894,355	683,684	1,072,144	1,848,140	2,904,594	2,904,594	2,904,594	2,904,594	2,904,594	2,904,594
	Prepayments - O&M	3,884,427	1,256,459	1,086,223	915,893	1,120,562	908,565	702,518	1,083,701	1,858,370	2,904,594	2,904,594	2,904,594	2,904,594	2,904,594	2,904,594
1650004	Prepaid Interest	209,116	309,147	816,319	1,010,193	4,541,293	2,597,967	1,279,454	2,520,137	437,891						
	Prepayments - Interest and Dividends	209,116	309,147	816,319	1,010,193	4,541,293	2,597,967	1,279,454	2,520,137	437,891	-	-	-	-	-	-
	Prepayments and Other Current Assets	**4,093,544**	**1,565,606**	**1,902,542**	**1,926,086**	**5,661,855**	**3,506,532**	**1,981,972**	**3,603,837**	**2,296,261**	**2,904,594**	**2,904,594**	**2,904,594**	**2,904,594**	**2,904,594**	**2,904,594**
	TOTAL CURRENT ASSETS	**1,101,145,395**	**1,133,982,827**	**901,225,223**	**1,618,739,347**	**1,840,256,026**	**1,864,725,642**	**1,440,138,268**	**1,568,461,678**	**1,351,267,297**	**805,810,395**	**784,822,391**	**1,283,894,283**	**1,589,281,605**	**1,683,241,592**	**1,609,874,437**
1010001	Plant in Service	980,533	1,688,345	1,812,270	1,926,078	1,840,760	1,853,525	1,861,898	1,877,290	1,889,335	2,088,027	2,188,612	2,306,264	2,457,080	2,730,551	3,242,185
1060001	Const Not Classifd	142,576	123,925	18,768	(85,317)	12,765	8,373	15,392	12,045	87,648						
	Electric Production	**1,123,109**	**1,812,270**	**1,831,038**	**1,840,760**	**1,853,525**	**1,861,898**	**1,877,290**	**1,889,335**	**1,976,983**	**2,088,027**	**2,188,612**	**2,306,264**	**2,457,080**	**2,730,551**	**3,242,185**
1070000	Construction Work In Progress	-	-	-	-	-	-	-	-	-						
1070001	CWIP - Project	2,754	4,361	4,468	4,593	4,758	4,855	5,033	5,184	5,336	4,233	18,800	52,781	109,164	98,162	3,051
	Construction Work-in-Progress	**2,754**	**4,361**	**4,468**	**4,593**	**4,758**	**4,855**	**5,033**	**5,184**	**5,336**	**4,233**	**18,800**	**52,781**	**109,164**	**98,162**	**3,051**
	TOTAL PROPERTY, PLANT and EQUIPMENT	**1,125,863**	**1,816,632**	**1,835,507**	**1,845,353**	**1,858,282**	**1,866,753**	**1,882,323**	**1,894,519**	**1,982,319**	**2,092,260**	**2,207,412**	**2,359,046**	**2,566,244**	**2,828,713**	**3,245,236**
1110001	A/P for Amort of Plt	(573,459)	(831,072)	(857,671)	(884,582)	(911,655)	(938,942)	(966,367)	(994,050)	(1,021,933)	(1,021,933)	(1,021,933)	(1,021,933)	(1,021,933)	(1,021,933)	(1,021,933)
	less: Accumulated Depreciation and Amortization	**(573,459)**	**(831,072)**	**(857,671)**	**(884,582)**	**(911,655)**	**(938,942)**	**(966,367)**	**(994,050)**	**(1,021,933)**	**(1,021,933)**	**(1,021,933)**	**(1,021,933)**	**(1,021,933)**	**(1,021,933)**	**(1,021,933)**
	NET PROPERTY, PLANT and EQUIPMENT	**552,404**	**985,560**	**977,836**	**960,771**	**946,627**	**927,811**	**915,955**	**900,470**	**960,386**	**1,070,327**	**1,185,480**	**1,337,113**	**1,544,311**	**1,806,780**	**2,223,303**
2543001	SFAS109 Flow Thru Def FIT Liab	(8,476,738)	(5,902,197)	(5,887,747)	(5,892,522)	(5,409,329)	(5,409,570)	(5,316,323)	(5,384,302)	(5,381,028)	(5,363,702)	(5,363,702)	(5,363,702)	(5,363,702)	(5,363,702)	(5,363,702)
2544001	SFAS 109 Exces Deferred FIT	-	17,327	17,327	17,327	17,327	17,327	17,327	17,327	17,327						
	Net Regulatory Assets	**(8,476,738)**	**(5,884,871)**	**(5,870,421)**	**(5,875,195)**	**(5,392,003)**	**(5,392,243)**	**(5,298,996)**	**(5,366,976)**	**(5,363,702)**	**(5,363,702)**	**(5,363,702)**	**(5,363,702)**	**(5,363,702)**	**(5,363,702)**	**(5,363,702)**
1231001	Invest in Common Stock of Subs	988,558,998	990,582,170	990,582,170	990,582,170	990,582,170	990,582,170	990,582,170	990,582,170	990,582,170						
1231002	Invest in Prem on Subs Stock	4,264,017	4,264,017	4,264,017	4,264,017	4,264,017	4,264,017	4,264,017	4,264,017	4,264,017						
1231003	Capital Contributions to Subs	10,865,781,583	11,165,612,543	11,317,259,633	11,340,044,643	11,409,638,867	11,429,754,650	11,583,488,863	11,689,584,544	11,729,370,397						
1231005	Invest in Subs Retained Erngs	6,424,768,596	7,557,975,126	7,766,195,051	7,662,544,156	7,829,450,475	7,918,750,019	7,906,736,976	8,144,358,504	8,350,721,150	21,088,940,492	21,303,395,141	21,455,500,960	21,624,097,704	21,823,444,064	21,074,937,735
	Investments in Consol Subs	18,283,373,194	19,718,433,857	20,078,300,872	19,997,434,988	20,233,935,530	20,343,350,856	20,485,072,026	20,828,789,236	21,074,937,735	21,088,940,492	21,303,395,141	21,455,500,960	21,624,097,704	21,823,444,064	21,074,937,735
1230001	Nonconsol Assoc Co-Cost Basis	3,978,080	3,978,080	3,978,080	3,978,080	3,978,080	3,978,080	3,978,080	3,978,080	3,978,080	3,978,080	3,978,080	3,978,080	3,978,080	3,978,080	3,978,080
1231101	Invest Nonconsol Subs-Equity	-	3,750,000	3,593,750	3,437,500	3,281,250	3,125,000	2,968,750	2,812,500	2,656,250	2,656,250	2,656,250	2,656,250	2,656,250	2,656,250	2,321,443,505
	Investments in Non-Consol Subs	3,978,080	7,728,080	7,571,830	7,415,580	7,259,330	7,103,080	6,946,830	6,790,580	6,634,330	6,634,330	6,634,330	6,634,330	6,634,330	6,634,330	2,325,421,585
	Investments in Power and Distribution Projects	**18,287,351,274**	**19,726,161,937**	**20,085,872,702**	**20,004,850,568**	**20,241,194,860**	**20,350,453,936**	**20,492,018,856**	**20,835,579,816**	**21,081,572,065**	**21,095,574,822**	**21,310,029,471**	**21,462,135,290**	**21,630,732,034**	**21,830,078,394**	**23,400,359,319**
1231007	Excess Cost - Invest Over Book	37,060,693	37,060,693	37,060,693	37,060,693	37,060,693	37,060,693	37,060,693	37,060,693	37,060,693	37,060,693	37,060,693	37,060,693	37,060,693	37,060,693	37,060,693
	Goodwill	**37,060,693**	**37,060,693**	**37,060,693**	**37,060,693**	**37,060,693**	**37,060,693**	**37,060,693**	**37,060,693**	**37,060,693**	**37,060,693**	**37,060,693**	**37,060,693**	**37,060,693**	**37,060,693**	**37,060,693**
1240001	Other Investments - Associated	20,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	65,000,000
	Other Investments - General	20,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	65,000,000
1840031	Affil Transactions-Cash Clrng	-	-	-	(66,010)	-	-	-	-	-						
	Clearing Accounts Expense	-	-	-	(66,010)	-	-	-	-	-	-	-	-	-	-	-
1860002	Deferred Expenses	2,645	0	364,389	273,605	271,986	446,582	366,502	338,144	435,100	1,282,336	1,282,336	1,282,336	1,282,336	1,282,336	1,282,338
	Other Defd Debits - O&M	2,645	0	364,389	273,605	271,986	446,582	366,502	338,144	435,100	1,282,336	1,282,336	1,282,336	1,282,336	1,282,336	1,282,338

Southwestern Electric Power Company
Balance Sheet - AEP, Inc.
Test Year Ending December 31, 2018
Docket No. 19-008-U

100 - American Electric Power Co.
BALANCE SHEET

Jul 2018 Layout: GAAP_BS1
17A V2018-07-31 Account: GL_ACCT_SEC Business Unit: 100

		Year End December Dec YTD 2016	Year End December Dec YTD 2017	Actual Jan YTD 2018	Actual Feb YTD 2018	Actual Mar YTD 2018	Actual Apr YTD 2018	Actual May YTD 2018	Actual Jun YTD 2018	Actual Jul YTD 2018	Budget Aug YTD 2018	Budget Sep YTD 2018	Budget Oct YTD 2018	Budget Nov YTD 2018	Budget Dec YTD 2018	Budget Dec YTD 2019
1650030	Other Prepayments - Long Term	766,667	666,667	658,333	650,000	641,667	633,333	625,000	616,667	608,333						
1860153	Unamortized Credit Line Fees	346,666	888,848	839,049	818,584	770,730	750,967	895,117	870,925	847,236						
	Other Defd Debits - Other	1,113,333	1,555,514	1,497,382	1,468,584	1,412,396	1,384,301	1,520,117	1,487,592	1,455,570	-	-	-	-	-	-
	Other Non Current Assets	**21,115,978**	**51,555,514**	**51,861,772**	**51,742,189**	**51,684,383**	**51,830,883**	**51,886,620**	**51,825,735**	**51,890,669**	**51,282,336**	**51,282,336**	**51,282,336**	**51,282,336**	**51,282,336**	**66,282,338**
	TOTAL OTHER NON-CURRENT ASSETS	**18,337,051,207**	**19,808,893,274**	**20,168,924,746**	**20,087,778,255**	**20,324,547,933**	**20,433,953,270**	**20,575,667,173**	**20,919,099,269**	**21,165,159,725**	**21,178,554,149**	**21,393,008,798**	**21,545,114,617**	**21,713,711,362**	**21,913,057,721**	**23,498,338,649**
	TOTAL ASSETS	**19,438,749,005**	**20,943,861,660**	**21,071,127,804**	**21,707,478,373**	**22,165,750,586**	**22,299,606,723**	**22,016,721,396**	**22,488,461,416**	**22,517,387,408**	**21,985,434,871**	**22,179,016,669**	**22,830,346,013**	**23,304,537,277**	**23,598,106,094**	**25,110,436,389**
	LIABILITIES															
2320001	Accounts Payable - Regular	2,267,879	3,332,080	252,520	1,932,799	302,418	217,921	569,214	2,682,448	1,350,484	1,548,264	1,548,264	1,548,264	1,548,264	1,548,264	1,548,264
	Acct Payable - Regular	2,267,879	3,332,080	252,520	1,932,799	302,418	217,921	569,214	2,682,448	1,350,484	1,548,264	1,548,264	1,548,264	1,548,264	1,548,264	1,548,264
2320008	Miscellaneous Liabilities	23,511	25,786	-	-	-	-	-	-	-						
2320076	Corporate Credit Card Liab	-	381	94	-	-	-	-	-	-						
	Acct Payable - Other	23,511	26,167	94	-	-	-	-	-	-	-	-	-	-	-	-
2320002	Unvouchered Invoices	239,480	614,941	690,136	724,299	87,886	4,355,883	1,953,429	135,868	197,781						
	Acct Payable - Unvouchered Invoices	239,480	614,941	690,136	724,299	87,886	4,355,883	1,953,429	135,868	197,781	-	-	-	-	-	-
	General Accounts Payable	2,530,869	3,973,188	942,750	2,657,097	390,304	4,573,804	2,522,643	2,818,316	1,548,264	1,548,264	1,548,264	1,548,264	1,548,264	1,548,264	1,548,264
2340001	A/P Assoc Co - InterUnit G/L	724,221	774,156	2,021,542	2,588,630	1,633,280	407,278	3,504,525	66,240,026	464,251	1,209,075	1,209,075	1,209,075	1,209,075	1,209,075	1,209,075
2340027	A/P Assoc Co - Intercompany	145,239	13,562	2,853	14,203	124,368	43,039	32,079	109,812	49,089						
2340029	A/P Assoc Co - AEPSC Bills	1,312,139	1,506,637	665,235	908,942	5,073,675	483,818	720,034	521,606	694,306						
2340030	A/P Assoc Co - InterUnit A/P	-	125	-	-	-	10,164	-	-	1,429						
	Associated Companies Accounts Payable	2,181,600	2,294,481	2,689,630	3,511,776	6,831,323	944,300	4,256,638	66,871,445	1,209,075	1,209,075	1,209,075	1,209,075	1,209,075	1,209,075	1,209,075
	Accounts Payable	**4,712,470**	**6,267,669**	**3,632,380**	**6,168,874**	**7,221,627**	**5,518,103**	**6,779,281**	**69,689,761**	**2,757,340**	**2,757,340**	**2,757,340**	**2,757,340**	**2,757,340**	**2,757,340**	**2,757,340**
2330000	Corp Borrow Program (NP-Assoc)	193,438,995	465,144,994	474,407,152	505,762,076	473,803,702	481,399,391	468,514,790	513,735,899	462,905,535	376,101,853	379,020,431	376,501,383	374,459,515	384,842,686	269,460,079
	Advances from Affiliates	**193,438,995**	**465,144,994**	**474,407,152**	**505,762,076**	**473,803,702**	**481,399,391**	**468,514,790**	**513,735,899**	**462,905,535**	**376,101,853**	**379,020,431**	**376,501,383**	**374,459,515**	**384,842,686**	**269,460,079**
2310002	Commercial Paper	1,040,000,000	898,550,000	798,000,000	1,267,000,000	1,886,200,000	1,926,250,000	1,386,250,000	1,814,000,000	1,755,000,000	1,077,979,243	1,387,113,111	1,930,904,964	1,311,421,153	1,777,233,188	1,846,038,013
	Short-Term Debt	**1,040,000,000**	**898,550,000**	**798,000,000**	**1,267,000,000**	**1,886,200,000**	**1,926,250,000**	**1,386,250,000**	**1,814,000,000**	**1,755,000,000**	**1,077,979,243**	**1,387,113,111**	**1,930,904,964**	**1,311,421,153**	**1,777,233,188**	**1,846,038,013**
2240506	Senior Unsecured Notes-Current	550,000,000	-	-	-	-	-	-	-	-						499,261,888
2240507	MTM FAS133 FV Hedge - Current	(1,377,033)	2,458,119	2,458,119	2,458,119	1,720,789	1,720,789	1,720,789	(738,112)	(738,112)	(738,112)	(738,112)	(738,112)	(738,112)	(738,112)	-
	Long-Term Debt Due Within One Year Non-Affiliated	**548,622,967**	**2,458,119**	**2,458,119**	**2,458,119**	**1,720,789**	**1,720,789**	**1,720,789**	**(738,112)**	**(738,112)**	**(738,112)**	**(738,112)**	**(738,112)**	**(738,112)**	**(738,112)**	**499,261,888**
2450517	Deriv-Hdg-Unreal Ls-FV-Int-Cur	1,376,050	-	-	-	-	-	-	738,112	738,112	738,112	738,112	738,112	738,112	738,112	738,112
	Risk Management Liabilities	**1,376,050**	**-**	**-**	**-**	**-**	**-**	**-**	**738,112**	**738,112**	**738,112**	**738,112**	**738,112**	**738,112**	**738,112**	**738,112**
2360001	Federal Income Tax	(17,703,664)	(40,223,907)	(40,223,907)	(40,223,907)	(40,306,041)	(40,278,041)	29,721,959	29,616,648	29,616,648	29,564,623	29,564,621	29,564,621	29,564,621	26,521,396	26,528,840
236000216	State Income Taxes	(85,098)	-	-	-	-	-	-	-	-						
236000217	State Income Taxes	-	(50,025)	(50,025)	(50,025)	(50,025)	(50,050)	(50,050)	(50,050)	(50,050)						
236001214	State Franchise Taxes	-	(1,575)	(1,575)	(1,575)	(1,575)	(1,575)	(1,575)	(1,575)	(1,575)						
236001216	State Franchise Taxes	(450)	-	-	-	-	-	-	-	-						
236001217	State Franchise Taxes	-	(400)	(400)	(400)	(400)	(400)	(400)	(400)	(400)						
2360501	Fed Inc Tax-Short Term FIN48	(89,967,712)	-	-	-	3,441,351	3,441,351	3,441,351	3,441,351	-						
	Accrued Taxes	**(107,756,924)**	**(40,275,907)**	**(40,275,907)**	**(40,275,907)**	**(36,916,690)**	**(36,888,715)**	**33,111,285**	**33,005,974**	**29,564,623**	**29,564,623**	**29,564,621**	**29,564,621**	**29,564,621**	**26,521,396**	**26,528,840**
2370006	Interest Accrd-Sen Unsec Notes	984,186	3,585,740	6,231,283	8,873,022	11,700,984	14,484,382	5,600,724	4,181,161	7,232,335	10,380,251	13,346,918	16,313,584	8,894,924	11,073,486	17,485,986
	Interested Accrued - General	984,186	3,585,740	6,231,283	8,873,022	11,700,984	14,484,382	5,600,724	4,181,161	7,232,335	10,380,251	13,346,918	16,313,584	8,894,924	11,073,486	17,485,986
	Interested Accrued - Affiliated	-	-	-	-	-	-	-	-	-						
	Accrued Interest	**984,186**	**3,585,740**	**6,231,283**	**8,873,022**	**11,700,984**	**14,484,382**	**5,600,724**	**4,181,161**	**7,232,335**	**10,380,251**	**13,346,918**	**16,313,584**	**8,894,924**	**11,073,486**	**17,485,986**
2420520	Accr Defer Compensation Ben	311,866	392,544	392,544	392,544	347,761	347,761	-	358,400	358,400						
	Misc Employee Benefits	311,866	392,544	392,544	392,544	347,761	347,761	-	358,400	358,400	-	-	-	-	-	-
2420511	Control Cash Disburse Account	421,084	232,820	655,784	722,657	220	16,371	176,074	350,143	74						
	Control Cash Disbursement Account	421,084	232,820	655,784	722,657	220	16,371	176,074	350,143	74	-	-	-	-	-	-
2420000	Misc Current & Accrued Liab	3,079,529	3,576,056	3,709,091	2,277,126	3,547,694	3,639,062	3,456,325	3,579,726	3,744,594	5,686,587	5,686,587	5,686,587	5,686,587	5,686,587	5,686,587
2420529	1St Chic-Sharehold Serv-Agent	85,000	73,000	73,000	73,000	73,000	73,000	73,000	73,000	73,000						
2420551	Unclaimed Dividends	1,960,096	2,045,551	1,362,850	1,218,189	1,981,026	1,348,208	1,218,812	1,885,946	1,346,851						
2420643	Accrued Audit Fees	455,103	0	96,983	193,966	310,293	413,724	238,732	60,237	163,668						
	Misc Current and Accrued Liabilities	5,579,728	5,694,607	5,241,924	3,762,281	5,912,013	5,473,995	4,986,869	5,598,910	5,328,113	5,686,587	5,686,587	5,686,587	5,686,587	5,686,587	5,686,587
	Other Current Liabilities	**6,312,678**	**6,319,971**	**6,290,253**	**4,877,483**	**6,259,994**	**5,838,127**	**5,162,942**	**6,307,452**	**5,686,587**	**5,686,587**	**5,686,587**	**5,686,587**	**5,686,587**	**5,686,587**	**5,686,587**
	TOTAL CURRENT LIABILITIES	**1,687,690,422**	**1,342,050,586**	**1,250,743,280**	**1,754,863,667**	**2,349,990,406**	**2,398,322,076**	**1,907,139,810**	**2,440,920,248**	**2,263,146,420**	**1,502,469,897**	**1,817,489,008**	**2,361,728,479**	**1,732,784,140**	**2,208,114,682**	**2,667,956,845**
	Long-Term Debt - Affiliated	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**						
1810003	Unamort Debt Exp Notes Payable	-	(19,277)	(24,753)	(24,753)	(24,753)	(24,753)	(24,753)	(24,753)	(24,753)						
1810006	Unamort Debt Exp - Sr Unsec Nt	(2,009,708)	(7,587,155)	(7,473,640)	(7,358,644)	(7,232,883)	(7,107,122)	(6,981,361)	(6,855,600)	(6,729,840)						
2240006	Senior Unsecured Notes	300,000,000	1,300,000,000	1,300,000,000	1,300,000,000	1,300,000,000	1,300,000,000	1,300,000,000	1,300,000,000	1,300,000,000	1,293,363,393	1,293,481,379	1,293,599,366	2,287,275,685	2,287,452,004	2,584,464,504
	Long-Term Debt - Non Affiliated	**297,990,292**	**1,292,393,569**	**1,292,501,607**	**1,292,616,603**	**1,292,742,364**	**1,292,868,125**	**1,292,993,885**	**1,293,119,646**	**1,293,245,407**	**1,293,363,393**	**1,293,481,379**	**1,293,599,366**	**2,287,275,685**	**2,287,452,004**	**2,584,464,504**
2240007	MTM of LTD - FAS133 FV Hedge	(0)	(8,851,317)	(8,851,317)	(8,851,317)	(22,343,875)	(22,343,875)	(22,343,875)	(27,226,313)	(27,226,313)	(28,747,207)	(28,721,652)	(28,696,096)	(28,670,541)	(28,644,985)	(28,338,319)
2260006	Unam Disc LTD-Dr-Sr Unsec Note	(470,192)	(1,758,025)	(1,727,800)	(1,697,575)	(1,667,350)	(1,637,125)	(1,606,900)	(1,576,675)	(1,546,450)						
	Long-Term Debt - Premiums and Discounts Unamort	**(470,192)**	**(10,609,342)**	**(10,579,117)**	**(10,548,892)**	**(24,011,225)**	**(23,981,000)**	**(23,950,775)**	**(28,802,988)**	**(28,772,763)**	**(28,747,207)**	**(28,721,652)**	**(28,696,096)**	**(28,670,541)**	**(28,644,985)**	**(28,338,319)**
2450017	Deriv-Hdg-Unreal Ls-FV-Int-L/T	-	8,616,379	8,616,379	8,616,379	22,343,875	22,343,875	22,343,875	27,226,313	27,226,313	27,226,313	27,226,313	27,226,313	27,226,313	27,226,313	27,226,313
	Long-Term Risk Management Liabilities	**-**	**8,616,379**	**8,616,379**	**8,616,379**	**22,343,875**	**22,343,875**	**22,343,875**	**27,226,313**	**27,226,313**	**27,226,313**	**27,226,313**	**27,226,313**	**27,226,313**	**27,226,313**	**27,226,313**
1901001	Accum Deferred FIT - Other	(56,183,817)	(22,427,828)	(22,414,140)	(22,414,140)	(22,332,006)	(22,332,006)	(22,332,006)	(21,877,450)	(21,877,450)	(29,771,545)	(29,771,545)	(29,771,545)	(29,771,545)	(29,771,545)	(29,771,545)
1902001	Accum Defd FIT - Oth Inc & Ded	(281,562)	(4,102)	(4,102)	(4,102)	(4,102)	(4,102)	(4,102)	(0)	(0)						

Southerwestern Electric Power Company
Balance Sheet - AEP, Inc.
Test Year Ending December 31, 2018
Docket No. 19-008-U

100 - American Electric Power Co.
BALANCE SHEET

Schedule E-17B HC

Jul 2018 Layout: GAAP_BS1
17A V2018-07-31 Account: GL_ACCT_SEC Business Unit: 100

Account	Description	Year End December Dec YTD 2016	Year End December Dec YTD 2017	Actual Jan YTD 2018	Actual Feb YTD 2018	Actual Mar YTD 2018	Actual Apr YTD 2018	Actual May YTD 2018	Actual Jun YTD 2018	Actual Jul YTD 2018	Budget Aug YTD 2018	Budget Sep YTD 2018	Budget Oct YTD 2018	Budget Nov YTD 2018	Budget Dec YTD 2018	Budget Dec YTD 2019
1903001	Acc Dfd FIT - FAS109 Flow Thru	(12,526,837)	(8,429,281)	(8,417,219)	(8,415,635)	(7,932,541)	(7,930,005)	(7,834,807)	(7,901,007)	(7,897,734)						
1904001	Accum Dfd FIT - FAS 109 Excess	-	3,639	3,639	3,639	3,639	3,639	3,639	3,639	3,639						
	DFIT & DSIT Reclass (A/C 190)	(68,992,216)	(30,857,572)	(30,831,822)	(30,830,238)	(30,265,010)	(30,262,474)	(30,167,276)	(29,774,819)	(29,771,545)	(29,771,545)	(29,771,545)	(29,771,545)	(29,771,545)	(29,771,545)	(29,771,545)
2360901	Accum Defd FIT- IRS Audit	(3,580,358)	(3,580,358)	(3,580,358)	(3,580,358)	(3,580,358)	(3,580,358)	(3,580,358)	-	-						
2823001	Acc Dfrd FIT FAS 109 Flow Thru	-	48,463	54,521	54,521	54,521	54,521	54,521	54,521	54,521						
2830015	ADIT-Fed-Hdg-CF-Int Rate	-	506,129	499,007	497,582	493,309	489,035	484,762	480,488	476,215						
2831001	Accum Deferred FIT - Other	-	-	(13,688)	(13,688)	(13,688)	(13,688)	(13,688)	(13,688)	(13,688)						
2833001	Acc Dfd FIT FAS 109 Flow Thru	4,050,099	2,478,621	2,474,951	2,468,592	2,468,691	2,465,915	2,463,963	2,462,185	2,462,185	3,168,427	3,343,933	3,519,440	3,694,947	3,870,454	5,200,417
2834001	Acc Defd FIT - SFAS 109 Excess	-	13,688	13,688	13,688	13,688	13,688	13,688	13,688	13,688						
	Accum Deferred Income Tax Credit	469,741	(533,457)	(551,880)	(559,663)	(563,838)	(570,888)	(577,112)	2,997,193	2,992,920	3,168,427	3,343,933	3,519,440	3,694,947	3,870,454	5,200,417
	Deferred Income Taxes	**(68,522,475)**	**(31,391,029)**	**(31,383,702)**	**(31,389,901)**	**(30,828,848)**	**(30,833,361)**	**(30,744,388)**	**(26,777,626)**	**(26,778,625)**	**(26,603,119)**	**(26,427,612)**	**(26,252,105)**	**(26,076,598)**	**(25,901,092)**	**(24,571,128)**
2283001	Deferred Compensation Plan	20,274,596	27,020,547	27,020,547	27,020,547	25,240,394	25,240,394	25,240,394	25,624,141	25,624,141	25,624,141	25,624,141	25,624,141	25,624,141	25,624,141	25,624,141
	Employee Benefits and Pension Obligations	**20,274,596**	**27,020,547**	**27,020,547**	**27,020,547**	**25,240,394**	**25,240,394**	**25,240,394**	**25,624,141**	**25,624,141**	**25,624,141**	**25,624,141**	**25,624,141**	**25,624,141**	**25,624,141**	**25,624,141**
2360601	Fed Inc Tax-Long Term FIN48	(139,007)	(139,007)	(139,007)	(139,007)	-	-	-	139,007	-						
2360801	Federal Income Tax - IRS Audit	3,580,358	3,580,358	3,580,358	3,580,358	-	-	-	(3,580,358)	-						
2370048	Acrd Int.- FIT Reserve - LT	514,240	643,822	643,822	643,822	663,818	663,818	663,818	181,249	181,249						
	Def Credits - Income Tax	3,955,591	4,085,173	4,085,173	4,085,173	663,818	663,818	663,818	###############	181,249	-	-	-	-	-	-
2110010	MPIC Stock Based Comp Units	-	11,938,830	12,980,013	14,037,628	17,009,046	19,089,190	21,072,210	23,577,649	25,662,349	31,316,944	30,967,297	30,967,297	30,967,297	30,638,385	29,364,203
2530000	Other Deferred Credits	10,500,825	7,427,007	7,270,757	7,114,507	6,608,610	6,452,360	6,296,110	5,810,947	5,654,697						
2530175	Legal Contingencies	-	-	-	-	-	-	-	(102)	(102)						
	Def Credits - Other	10,500,825	19,365,837	20,250,770	21,152,135	23,617,656	25,541,550	27,368,320	29,388,494	31,316,944	31,316,944	30,967,297	30,967,297	30,967,297	30,638,385	29,364,203
	Other Non-Current Liabilities	**14,456,416**	**23,451,010**	**24,335,943**	**25,237,308**	**24,281,474**	**26,205,368**	**28,032,138**	**26,128,392**	**31,498,193**	**31,316,944**	**30,967,297**	**30,967,297**	**30,967,297**	**30,638,385**	**29,364,203**
	TOTAL NON-CURRENT LIABILITIES	**263,728,638**	**1,309,481,134**	**1,310,511,658**	**1,311,552,044**	**1,309,768,033**	**1,311,843,400**	**1,313,915,129**	**1,316,517,879**	**1,322,042,666**	**1,322,180,465**	**1,322,149,867**	**1,322,468,915**	**2,316,346,297**	**2,316,394,766**	**2,613,769,715**
	TOTAL LIABILITIES	**1,951,419,060**	**2,651,531,719**	**2,561,254,937**	**3,066,415,712**	**3,659,758,439**	**3,710,165,476**	**3,221,054,939**	**3,757,438,126**	**3,585,189,086**	**2,824,650,362**	**3,139,638,875**	**3,684,197,394**	**4,049,130,437**	**4,524,509,448**	**5,281,726,560**
	COMMON SHAREHOLDERS' EQUITY															
2010002	Common Stck Issd-Nonaffiliated	3,328,315,376	3,329,369,182	3,330,484,589	3,331,260,767	3,332,655,101	3,332,729,591	3,333,919,488	3,335,350,567	3,335,426,513						
	Common Stock	**3,328,315,376**	**3,329,369,182**	**3,330,484,589**	**3,331,260,767**	**3,332,655,101**	**3,332,729,591**	**3,333,919,488**	**3,335,350,567**	**3,335,426,513**	-	-	-	-	-	-
2100000	Gain Rsle/Cancl Req Cap Stock	982,232	982,232	982,232	982,232	982,232	982,232	982,232	982,232	982,232						
2110000	Miscellaneous Paid-In Capital	566,019,345	566,019,345	566,019,345	566,019,345	566,019,345	566,019,345	566,019,345	566,019,345	566,019,345						
2110009	MPIC - restricted stock units	59,298,444	66,322,275	67,155,593	68,038,898	69,916,702	70,923,617	66,209,189	67,534,057	68,595,625						
2110012	MPIC - Excess Tax Benefit	5,987,752	5,987,752	5,987,752	5,987,752	5,987,752	5,987,752	5,987,752	5,987,752	5,987,752						
2110013	APIC Pool - SFAS 123R	28,694,958	28,694,958	28,694,958	28,694,958	28,694,958	28,694,958	28,694,958	28,694,958	28,694,958						
2110019	MPIC StkBsdComp-Career Shares	-	47,974,858	47,974,858	49,488,500	48,187,672	47,976,783	47,976,783	48,366,849	48,318,088						
2110020	MPIC StkComp-Units NonMezz	-	-	-	-	(122,396)	(122,396)	(122,396)	112,294	112,294						
2140000	Capital Stock Expense	(132,518,295)	(132,518,295)	(132,518,295)	(132,518,295)	(132,518,295)	(132,518,295)	(132,518,295)	(132,518,295)	(132,518,295)						
	Paid In Capital	**528,464,436**	**583,463,125**	**584,296,444**	**586,693,389**	**587,147,970**	**587,943,996**	**583,229,569**	**585,179,192**	**586,191,999**	-	-	-	-	-	-
2070001	Premium on Common Stock	5,780,954,147	5,792,117,929	5,803,093,936	5,810,238,357	5,820,925,837	5,821,382,759	5,824,161,811	5,836,964,306	5,837,624,595	19,159,005,222	19,037,610,695	19,144,393,708	19,253,664,117	19,071,866,109	19,827,125,542
2070003	Prem on Pfd Stk n/s/t Mand Red	101	101	101	101	101	101	101	101	101						
	Premium on Capital Stock	**5,780,954,248**	**5,792,118,030**	**5,803,094,037**	**5,810,238,458**	**5,820,925,939**	**5,821,382,860**	**5,824,161,912**	**5,836,964,407**	**5,837,624,696**	**19,159,005,222**	**19,037,610,695**	**19,144,393,708**	**19,253,664,117**	**19,071,866,109**	**19,827,125,542**
	Net Income	589,069,113	1,914,472,303	204,616,044	313,653,434	455,691,548	537,791,027	744,795,640	970,803,476	1,170,245,543						
	Earnings before Preferred Stock	589,069,113	1,914,472,303	204,616,044	313,653,434	455,691,548	537,791,027	744,795,640	970,803,476	1,170,245,543	-	-	-	-	-	-
2151000	Appr Retnd Erngs-Amrt Rsv,Fed	4,577,501	4,577,501	4,577,501	4,577,501	4,577,501	4,577,501	4,577,501	4,577,501	4,577,501						
2160001	Unapprp Retnd Erngs-Unrstrictd	(10,975,151,800)	(12,052,105,241)	(13,274,265,485)	(13,262,485,511)	(13,262,485,511)	(13,262,485,511)	(13,262,485,511)	(13,262,485,511)	(13,262,485,511)						
2160002	Unapprp Retnd Erngs-Restrictd	5,900,000	5,900,000	5,900,000	5,900,000	5,900,000	5,900,000	5,900,000	5,900,000	5,900,000						
2161001	Unap Undist Consol Sub Erng	19,341,959,554	19,891,223,626	21,849,600,998	21,849,600,998	21,849,600,011	21,849,600,011	21,849,600,011	21,849,600,011	21,849,600,011						
4380002	Div Declrd - Common - NonAssoc	(1,115,697,272)	(1,175,444,131)	-	-	(305,200,801)	(305,200,801)	(305,200,801)	(610,667,710)	(610,667,710)						
4380003	Div Equiv - Restricted Stock	(1,061,210)	(2,811,044)	15,377	23,179	(1,028,611)	(998,454)	(1,016,301)	(2,367,515)	(2,367,515)						
4390000	Adj to Retained Earnings	-	-	-	(337,420)	16,361,322	16,361,322	16,361,322	16,361,322	16,361,322						
	Retained Earnings w/o Net Income	7,260,526,773	6,671,340,711	8,585,828,390	8,597,278,747	8,307,723,911	8,307,754,069	8,307,736,221	8,000,918,098	8,000,918,098	-	-	-	-	-	-
	Retained Earnings	**7,849,595,886**	**8,585,813,013**	**8,790,444,434**	**8,910,932,181**	**8,763,415,459**	**8,845,545,096**	**9,052,531,861**	**8,971,721,574**	**9,171,163,641**						
2190015	Accum OCI-Hdg-CF-Int Rate	-	1,566,591	1,553,363	1,871,857	1,855,781	1,839,704	1,823,627	1,807,551	1,791,474	1,779,287	1,767,099	1,754,912	1,742,724	1,730,537	1,584,287
	Accumulated Other Comprehensive Income (Loss)	**-**	**1,566,591**	**1,553,363**	**1,871,857**	**1,855,781**	**1,839,704**	**1,823,627**	**1,807,551**	**1,791,474**	**1,779,287**	**1,767,099**	**1,754,912**	**1,742,724**	**1,730,537**	**1,584,287**
	TOTAL SHAREHOLDERS' EQUITY	**17,487,329,946**	**18,292,329,941**	**18,509,872,867**	**18,640,996,652**	**18,506,000,249**	**18,589,441,247**	**18,795,666,457**	**18,731,023,290**	**18,932,198,323**	**19,160,784,508**	**19,039,377,794**	**19,146,148,619**	**19,255,406,841**	**19,073,596,646**	**19,828,709,829**
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**19,438,749,005**	**20,943,861,660**	**21,071,127,804**	**21,707,412,363**	**22,165,758,688**	**22,299,606,723**	**22,016,721,396**	**22,488,461,416**	**22,517,387,408**	**21,985,434,871**	**22,179,016,669**	**22,830,346,013**	**23,304,537,277**	**23,598,106,093**	**25,110,436,389**

Recap Schedules
E-1 HC

Southwestern Electric Power Company
Index F - Work Papers
Test Year Ending December 31, 2018
Docket No. 19-008-U

Southwestern Electric Power Company **SCHEDULE F-1.1**
Historical Test Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

HISTORICAL TEST YEAR

(1) Line No..	(2) Acct. Number	(3) Acct. Description	(4) Plant Balance Per Book End of Test Year (a) (B)	(5) Reclassifications (b)	(6) Adjusted Plant Balance End of Test Year (A) (B)	(7) Accumulated Depreciation Per Book End of Test Year (a) (B)
1			-		-	-
2				-		
		Note: This schedule is not required for a partially projected test year.				
3			-	-		-
4						
5				-		
6			-	-		-
7			-	-	-	-
8	Total		-	-	-	-

SCHEDULE F-1.2

Southwestern Electric Power Company
Partially Projected Test Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: This schedule shows original cost of utility plant in service and accumulated depreciation by account, subtotaled by function, for a partially projected test year. Schedule F-1.2 should only be completed if the company is filing a partially projected test year. Total amounts must reconcile to the recap schedules indicated.

PARTIALLY PROJECTED TEST YEAR

(1) Line No.	(2) Acct. Number	(3) Account Description	(4) Plant Balance Per Book End of Historical Portion of Test Year (a)	(5) Additions	(6) Projected Retirements	(7) Reclassification
		INTANGIBLE PLANT				
1	301	Organization	12,202			
2	302	Franchise and Consents	-			
3	303.2	Miscellaneous Intangible Plant-Software	97,658,520	32,663,367	(8,098,000)	
4						
5	107	CONSTRUCTION WORK IN PROGRESS				
6						
7		**TOTAL INTANGIBLE PLANT (b) (c)**	**97,670,722**	**32,663,367**	**(8,098,000)**	**-**
8						
9		**STEAM PRODUCTION PLANT**				
10						
11		**Gas & Oil Plants**				
12						
13		ARSENAL HILL				
14	310.3	Land Oil/Gas	370,798	-	-	
15	311.3	Structures & Improvements	5,798,815	-	-	
16	312.3	Boiler Plant Equipment	6,859,389	115,678	(36,425)	
17	314.3	Turbogenerator Units	4,779,908	80,610	(25,385)	
18	315.3	Accessory Electrical Equipment	1,210,371	20,412	(6,430)	
19	316.3	Misc. Power Plant Equip. Oil-Gas	7,033,251	118,610	(37,347)	
20	317.3	ARO Steam Prod Plt Oil/Gas	507,714	-	-	
21		Total	26,560,246	335,310	(105,587)	
22						
23		KNOX LEE				
24	310.3	Land Oil/Gas	102,781	-	-	
25	311.3	Structures & Improvements	8,323,697	108,226	(34,079)	
26	312.3	Boiler Plant Equipment	35,475,382	461,261	(145,247)	
27	314.3	Turbogenerator Units	21,777,901	283,161	(89,164)	
28	315.3	Accessory Electrical Equipment	4,056,413	52,742	(16,608)	
29	316.3	Misc. Power Plant Equip.	1,877,079	24,407	(7,685)	
30	317.3	ARO Steam Prod Plt Oil/Gas	2,036,608	-	-	
31		Total	73,649,860	929,797	(292,783)	-
32						
33		LIEBERMAN				

SCHEDULE F-1.2

Southwestern Electric Power Company
Partially Projected Test Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: This schedule shows original cost of utility plant in service and accumulated depreciation by account, subtotaled by function, for a partially projected test year. Schedule F-1.2 should only be completed if the company is filing a partially projected test year. Total amounts must reconcile to the recap schedules indicated.

(1) Line No.	(2) Acct. Number	(3) Account Description	(8) Projected Plant Balance End of Test Year (A)	(9) Accumulated Depreciation Per Book End of Historical Portion of Test Year	(10) Accumulated Depreciation @ December 31, 2018
		INTANGIBLE PLANT			
1	301	Organization	12,202	-	
2	302	Franchise and Consents	-		
3	303.2	Miscellaneous Intangible Plant-Software	122,223,886	50,016,984	50,972,631
4					
5	107	CONSTRUCTION WORK IN PROGRESS			
6					
7		**TOTAL INTANGIBLE PLANT (b) (c)**	**122,236,088**	**50,016,984**	**50,972,631**
8					
9		**STEAM PRODUCTION PLANT**			
10					
11		**Gas & Oil Plants**			
12					
13		ARSENAL HILL			
14	310.3	Land Oil/Gas	370,798	-	-
15	311.3	Structures & Improvements	5,798,815	5,304,885	5,401,472
16	312.3	Boiler Plant Equipment	6,938,642	5,927,443	6,035,367
17	314.3	Turbogenerator Units	4,835,133	4,343,231	4,422,311
18	315.3	Accessory Electrical Equipment	1,224,353	714,109	727,111
19	316.3	Misc. Power Plant Equip. Oil-Gas	7,114,514	4,427,055	4,507,661
20	317.3	ARO Steam Prod Plt Oil/Gas	507,714	260,140	264,877
21		Total	26,789,969	20,976,863	21,358,799
22					
23		KNOX LEE			
24	310.3	Land Oil/Gas	102,781	-	-
25	311.3	Structures & Improvements	8,397,844	7,638,697	7,777,778
26	312.3	Boiler Plant Equipment	35,791,395	30,637,303	31,195,132
27	314.3	Turbogenerator Units	21,971,898	18,288,530	18,621,517
28	315.3	Accessory Electrical Equipment	4,092,547	2,772,652	2,823,135
29	316.3	Misc. Power Plant Equip.	1,893,801	1,669,684	1,700,085
30	317.3	ARO Steam Prod Plt Oil/Gas	2,036,608	1,053,901	1,073,090
31		Total	74,286,874	62,060,767	63,190,737
32					
33		LIEBERMAN			

Southwestern Electric Power Company
Partially Projected Test Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: This schedule shows original cost of utility plant in service and accumulated depreciation by account, subtotaled by function, for a partially projected test year. Schedule F-1.2 should only be completed if the company is filing a partially projected test year. Total amounts must reconcile to the recap schedules indicated.

PARTIALLY PROJECTED TEST YEAR

(1) Line No.	(2) Acct. Number	(3) Account Description	(4) Plant Balance Per Book End of Historical Portion of Test Year (a)	(5) Additions	(6) Projected Retirements	(7) Reclassification
34	310.3	Land Oil/Gas	24,026	-	-	
35	311.3	Structures & Improvements	3,829,290	-	-	
36	312.3	Boiler Plant Equipment	18,441,276	315,403	(99,319)	
37	314.3	Turbogenerator Units	11,678,560	199,740	(62,896)	
38	315.3	Accessory Electrical Equipment	3,431,323	-	-	
39	316.3	Misc. Power Plant Equip.	2,137,095	-	-	
40	317.3	ARO Steam Prod Plt Oil/Gas	1,263,344	-	-	
41		Total	40,804,914	515,143	(162,215)	
42						
43		LONE STAR				
44	310	Land Oil/Gas	58,487	-	-	
45	311.0	Structures & Improvements	934,757	-	-	
46	312.0	Boiler Plant Equipment	4,148,920	-	-	
47	314.0	Turbogenerator Units	2,586,137	-	-	
48	315.0	Accessory Electrical Equipment	879,417	-	-	
49	316.0	Misc. Power Plant Equip.	201,389	-	-	
50	317	ARO Steam Prod Plt Oil/Gas	123,592	-	-	
51		Total	8,932,698	-	-	
52						
53		WILKES				
54	310	Land Oil/Gas	443,729	-	-	
55	311.0	Structures & Improvements	7,852,299	101,402	(31,929)	
56	312.0	Boiler Plant Equipment	47,176,722	609,227	(191,839)	
57	314.0	Turbogenerator Units	37,828,011	488,502	(153,824)	
58	315.0	Accessory Electrical Equipment	10,146,499	131,030	(41,260)	
59	316.0	Misc. Power Plant Equip.	9,042,813	116,776	(36,772)	
60	317	ARO Steam Prod Plt Oil/Gas	2,122,856	-	-	
61		Total	114,612,930	1,446,937	(455,624)	
62						
63		STALL				
64	310	Land Oil/Gas	53,286,732			

SCHEDULE F-1.2

Southwestern Electric Power Company
Partially Projected Test Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: This schedule shows original cost of utility plant in service and accumulated depreciation by account, subtotaled by function, for a partially projected test year. Schedule F-1.2 should only be completed if the company is filing a partially projected test year. Total amounts must reconcile to the recap schedules indicated.

(1) Line No.	(2) Acct. Number	(3) Account Description	(8) Projected Plant Balance End of Test Year (A)	(9) Accumulated Depreciation Per Book End of Historical Portion of Test Year	(10) Accumulated Depreciation @ December 31, 2018
34	310.3	Land Oil/Gas	24,026	-	-
35	311.3	Structures & Improvements	3,829,290	3,834,711	3,904,531
36	312.3	Boiler Plant Equipment	18,657,360	17,091,209	17,402,397
37	314.3	Turbogenerator Units	11,815,404	10,878,678	11,076,751
38	315.3	Accessory Electrical Equipment	3,431,323	2,207,358	2,247,547
39	316.3	Misc. Power Plant Equip.	2,137,095	1,747,038	1,778,848
40	317.3	ARO Steam Prod Plt Oil/Gas	1,263,344	802,015	816,617
41		Total	41,157,842	36,561,009	37,226,691
42					
43		LONE STAR			
44	310	Land Oil/Gas	58,487	-	-
45	311.0	Structures & Improvements	934,757	839,091	854,368
46	312.0	Boiler Plant Equipment	4,148,920	3,052,411	3,107,988
47	314.0	Turbogenerator Units	2,586,137	2,297,702	2,339,537
48	315.0	Accessory Electrical Equipment	879,417	530,973	540,641
49	316.0	Misc. Power Plant Equip.	201,389	101,131	102,971
50	317	ARO Steam Prod Plt Oil/Gas	123,591	116,541	118,663
51		Total	8,932,698	6,937,849	7,064,168
52					
53		WILKES			
54	310	Land Oil/Gas	443,729	-	-
55	311.0	Structures & Improvements	7,921,771	7,213,576	7,344,918
56	312.0	Boiler Plant Equipment	47,594,111	29,716,879	30,257,948
57	314.0	Turbogenerator Units	38,162,689	27,285,553	27,782,355
58	315.0	Accessory Electrical Equipment	10,236,269	4,382,813	4,462,613
59	316.0	Misc. Power Plant Equip.	9,122,818	3,326,116	3,386,676
60	317	ARO Steam Prod Plt Oil/Gas	2,122,856	723,061	736,226
61		Total	115,604,243	72,647,998	73,970,736
62					
63		STALL			
64	310	Land Oil/Gas	-	-	-

SCHEDULE F-1.2

Southwestern Electric Power Company
Partially Projected Test Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: This schedule shows original cost of utility plant in service and accumulated depreciation by account, subtotaled by function, for a partially projected test year. Schedule F-1.2 should only be completed if the company is filing a partially projected test year. Total amounts must reconcile to the recap schedules indicated.

PARTIALLY PROJECTED TEST YEAR

(1) Line No.	(2) Acct. Number	(3) Account Description	(4) Plant Balance Per Book End of Historical Portion of Test Year (a)	(5) Additions	(6) Projected Retirements	(7) Reclassification
65	311.0	Structures & Improvements	87,182,639	672,722	(211,833)	
66	312.0	Boiler Plant Equipment	169,008,177	1,100,642	(346,579)	
67	314.0	Turbogenerator Units	40,329,265	2,133,654	(671,863)	
68	315.0	Accessory Electrical Equipment	84,695,484	509,140	(160,323)	
69	316.0	Misc. Power Plant Equip.	-	1,069,244	(336,695)	
70	317	ARO Steam Prod Plt Oil/Gas	-			
71		Total	434,502,297	5,485,402	(1,727,293)	
72						
73		Total Gas & Oil Plants	699,062,946	8,712,589	(2,743,502)	
74						
75		Coal and Lignite Plants				
76		DOLET HILLS				
77	310	Land - Coal	1,510,615	-	-	
78	311.0	Structures & Improvements	56,188,715	715,013	(225,151)	
79	312.0	Boiler Plant Equipment	219,940,636	2,798,789	(881,304)	
80	314.0	Turbogenerator Units	39,642,457	504,457	(158,850)	
81	315.0	Accessory Electrical Equipment	12,041,188	153,225	(48,249)	
82	316.0	Misc. Power Plant Equip.	16,105,621	204,946	(64,535)	
83	317	Dolet Hills Generating ARO Ash Pond : SEP : PPAS	1,230,658	-	-	
84	317	Dolet Hills Generating Plant : SEP : PPDLH				
85		Total	346,659,890	4,376,430	(1,378,089)	
86						
87		FLINT CREEK				
88	310	Land	3,364,925	-	-	
89	311.0	Structures & Improvements	26,759,508	356,841	(112,367)	
90	312.0	Boiler Plant Equipment	295,043,459	3,934,441	(1,238,912)	
91	314.0	Turbogenerator Units	15,292,266	-	-	
92	315.0	Accessory Electrical Equipment	8,783,638	203,924	(64,213)	
93	316.0	Misc. Power Plant Equip.	6,074,378	117,131	(36,885)	
94	317	ARO#1 Flint Creek Ash Pond : SEP : PPFLCARO1	9,719,253	81,004	(25,506)	
95	317	ARO#2 Flint Creek Ash Pond : SEP : PPFLCARO2	-	-	-	

Southwestern Electric Power Company
Partially Projected Test Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: This schedule shows original cost of utility plant in service and accumulated depreciation by account, subtotaled by function, for a partially projected test year. Schedule F-1.2 should only be completed if the company is filing a partially projected test year. Total amounts must reconcile to the recap schedules indicated.

(1)	(2)	(3)	(8)	(9)	(10)
Line No.	Acct. Number	Account Description	Projected Plant Balance End of Test Year (A)	Accumulated Depreciation Per Book End of Historical Portion of Test Year	Accumulated Depreciation @ December 31, 2018
65	311.0	Structures & Improvements	53,747,621	11,855,081	12,070,933
66	312.0	Boiler Plant Equipment	87,936,702	12,971,667	13,207,849
67	314.0	Turbogenerator Units	170,469,967	2,017,165	2,053,893
68	315.0	Accessory Electrical Equipment	40,678,082	8,789,699	8,949,738
69	316.0	Misc. Power Plant Equip.	85,428,034	18,614,232	18,953,150
70	317	ARO Steam Prod Plt Oil/Gas	-		
71		Total	438,260,406	54,247,844	55,235,563
72					
73		Total Gas & Oil Plants	**705,032,032**	**253,432,330**	**258,046,694**
74					
75		Coal and Lignite Plants			
76		DOLET HILLS			
77	310	Land - Coal	1,510,615	9,534	9,534
78	311.0	Structures & Improvements	56,678,577	47,440,490	48,304,262
79	312.0	Boiler Plant Equipment	221,858,121	120,037,744	122,223,329
80	314.0	Turbogenerator Units	39,988,064	29,460,643	29,997,047
81	315.0	Accessory Electrical Equipment	12,146,164	9,291,794	9,460,974
82	316.0	Misc. Power Plant Equip.	16,246,032	11,752,430	11,966,412
83	317	Dolet Hills Generating ARO Ash Pond : SEP : PPAS	1,230,658	296,762	302,166
84	317	Dolet Hills Generating Plant : SEP : PPDLH			
85		Total	349,658,231	218,289,397	222,263,724
86					
87		FLINT CREEK			
88	310	Land	3,364,925	-	-
89	311.0	Structures & Improvements	27,003,982	16,094,982	16,388,032
90	312.0	Boiler Plant Equipment	297,738,988	46,272,826.74	47,109,457
91	314.0	Turbogenerator Units	15,431,977	8,465,813	8,619,954
92	315.0	Accessory Electrical Equipment	8,863,884	4,862,663	4,951,199
93	316.0	Misc. Power Plant Equip.	6,129,876	3,419,367	3,481,625
94	317	ARO#1 Flint Creek Ash Pond : SEP : PPFLCARO1	9,719,253	1,644,180	1,674,115
95	317	ARO#2 Flint Creek Ash Pond : SEP : PPFLCARO2	-		

SCHEDULE F-1.2

Southwestern Electric Power Company
Partially Projected Test Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: This schedule shows original cost of utility plant in service and accumulated depreciation by account, subtotaled by function, for a partially projected test year. Schedule F-1.2 should only be completed if the company is filing a partially projected test year. Total amounts must reconcile to the recap schedules indicated.

PARTIALLY PROJECTED TEST YEAR

(1) Line No.	(2) Acct. Number	(3) Account Description	(4) Plant Balance Per Book End of Historical Portion of Test Year (a)	(5) Additions	(6) Projected Retirements	(7) Reclassification
96	317	ARO#3 Flint Creek Ash Pond : SEP : PPFLCARO3				
97	317	Flint Creek Generating Plant : SEP : PPFLC		-	-	
98		Total	365,037,427	4,693,341	(1,477,883)	
99						
100		PIRKEY				
101	310	Land	5,843,029	-	-	
102	311.0	Structures & Improvements	108,542,725	-	-	
103	312.0	Boiler Plant Equipment	368,113,728	6,783,379	(2,136,009)	
104	314.0	Turbogenerator Units	50,945,628	-	-	
105	315.0	Accessory Electrical Equipment	18,049,322	332,603	(104,734)	
106	316.0	Misc. Power Plant Equip.	18,446,733	339,926	(107,041)	
107	317	ARO#1 Pirkey Ash Pond - TX SEP	20,646,276	-	-	
108	317	ARO#2 Pirkey Ash Pond - TX SEP				
109	317	ARO#3 Pirkey Ash Pond - TX SEP				
110	317	ARO#4 Pirkey Ash Pond - TX SEP				
111	317	ARO#5 Pirkey Ash Pond - TX SEP				
112	317	ARO#6 Pirkey Ash Pond - TX SEP				
113	317	Pirkey Generating Plant : SEP : PPPRK				
114		Total	590,587,440	7,455,908	(2,347,784)	
115						
116		WELSH				
117	310	Land	1,895,474			
118	311.0	Structures & Improvements	72,166,676	933,101	(293,824)	
119	312.0	Boiler Plant Equipment	577,718,735	7,469,789	(2,352,155)	
120	314.0	Turbogenerator Units	141,612,090	1,831,016	(576,566)	
121	315.0	Accessory Electrical Equipment	45,690,453	590,769	(186,025)	
122	316.0	Misc. Power Plant Equip.	21,215,410	274,311	(86,377)	
123	317	ARO#1 Welsh Landfill : SEP : PPWSHARO1	19,114,678			
124	317	ARO#2 Welsh Landfill : SEP : PPWSHARO2				
125	317	ARO#3 Welsh Landfill : SEP : PPWSHARO3				
126	317	ARO#4 Welsh Landfill : SEP : PPWSHARO4				

SCHEDULE F-1.2

Southwestern Electric Power Company
Partially Projected Test Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

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(1) Line No.	(2) Acct. Number	(3) Account Description	(8) Projected Plant Balance End of Test Year (A)	(9) Accumulated Depreciation Per Book End of Historical Portion of Test Year	(10) Accumulated Depreciation @ December 31, 2018
96	317	ARO#3 Flint Creek Ash Pond : SEP : PPFLCARO3			
97	317	Flint Creek Generating Plant : SEP : PPFLC			
98		Total	368,252,885	80,759,832	82,224,382
99					
100		PIRKEY			
101	310	Land	5,843,029	-	-
102	311.0	Structures & Improvements	108,542,725	98,748,955	100,546,926
103	312.0	Boiler Plant Equipment	372,761,096	236,566,766	240,874,053
104	314.0	Turbogenerator Units	50,945,628	47,663,761	48,531,599
105	315.0	Accessory Electrical Equipment	18,277,191	12,925,766	13,161,112
106	316.0	Misc. Power Plant Equip.	18,679,619	15,372,141	15,652,029
107	317	ARO#1 Pirkey Ash Pond - TX SEP	20,646,276	2,479,163	2,524,304
108	317	ARO#2 Pirkey Ash Pond - TX SEP			
109	317	ARO#3 Pirkey Ash Pond - TX SEP			
110	317	ARO#4 Pirkey Ash Pond - TX SEP			
111	317	ARO#5 Pirkey Ash Pond - TX SEP			
112	317	ARO#6 Pirkey Ash Pond - TX SEP			
113	317	Pirkey Generating Plant : SEP : PPPRK			
114		Total	595,695,564	413,756,552	421,290,023
115					
116		WELSH			
117	310	Land	1,895,473	-	-
118	311.0	Structures & Improvements	72,805,953	39,491,491	40,311,785
119	312.0	Boiler Plant Equipment	582,836,369	165,836,382	169,475,892
120	314.0	Turbogenerator Units	142,866,540	57,544,582	58,706,596
121	315.0	Accessory Electrical Equipment	46,095,197	14,729,502	15,051,834
122	316.0	Misc. Power Plant Equip.	21,403,344	14,159,686	14,427,502
123	317	ARO#1 Welsh Landfill : SEP : PPWSHARO1	19,114,678	2,742,896	2,792,839
124	317	ARO#2 Welsh Landfill : SEP : PPWSHARO2			
125	317	ARO#3 Welsh Landfill : SEP : PPWSHARO3			
126	317	ARO#4 Welsh Landfill : SEP : PPWSHARO4			

Southwestern Electric Power Company
Partially Projected Test Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

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			PARTIALLY PROJECTED TEST YEAR			
(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Acct. Number	Account Description	Plant Balance Per Book End of Historical Portion of Test Year (a)	Additions	Projected Retirements	Reclassification
127	317	Welsh Generating Plant : SEP : PPWSH				
128		Total	879,413,514	11,098,986	(3,494,947)	
129						
130		TURK				
131	310	Land	11,468,899	-	-	
132	310.1	Land Rights-coal	1,886,717	-	-	
133	311.0	Structures & Improvements	285,601,333	4,238,595	(1,334,687)	
134	312.0	Boiler Plant Equipment	986,401,348	14,639,134	(4,609,697)	
135	314.0	Turbogenerator Units	232,599,492	-	-	
136	315.0	Accessory Electrical Equipment	93,356,005	1,385,491	(436,277)	
137	316.0	Misc. Power Plant Equip.	48,018,866	712,645	(224,405)	
138	317	ARO#1 Turk Landfill : SEP : JWTGPARO1	2,179,313	-	-	
139		Total	1,661,511,973	20,975,865	(6,605,066)	
140						
141		**Total Coal and Lignite Plants**	**3,843,210,243**	**48,600,530**	**(15,303,769)**	
142						
143		RAIL CARS				
144	312.11	Rail Cars - Flint Creek	6,725,198	-	-	
145	312.11	Rail Cars - Welsh Plant	10,567,149	136,632	(43,025)	
146			17,292,347	136,632	(43,025)	
147						
148	310	Land - Coal Fired-Catahoula				
149	316	Misc Pwr Plant Equip-Coal- Alliance NE	-			
150			-			
151		Total Steam Production Plant	4,559,565,536	57,449,751	(18,090,296)	
152						
153		Other Production Plant				
154						
155		MATTISON				
156	340	Land	1,451,852	-	-	
157	341	Structures & Improvements	34,912,751	445,729	(140,354)	

Southwestern Electric Power Company
Partially Projected Test Year Depreciation Information
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(1) Line No.	(2) Acct. Number	(3) Account Description	(8) Projected Plant Balance End of Test Year (A)	(9) Accumulated Depreciation Per Book End of Historical Portion of Test Year	(10) Accumulated Depreciation @ December 31, 2018
127	317	Welsh Generating Plant : SEP : PPWSH			
128		Total	887,017,554	294,504,539	300,766,448
129					
130		TURK			
131	310	Land	11,468,899	-	-
132	310.1	Land Rights-coal	1,886,717	-	-
133	311.0	Structures & Improvements	288,505,241	32,397,430	32,987,306
134	312.0	Boiler Plant Equipment	996,430,785	116,256,879	118,373,625
135	314.0	Turbogenerator Units	232,599,492	28,998,108	29,526,090
136	315.0	Accessory Electrical Equipment	94,305,219	11,014,050	11,214,588
137	316.0	Misc. Power Plant Equip.	48,507,106	4,925,868	5,015,555
138	317	ARO#1 Turk Landfill : SEP : JWTGPARO1	2,179,313	290,906	296,203
139		Total	1,675,882,772	193,883,241	197,413,367
140					
141		**Total Coal and Lignite Plants**	**3,876,507,006**	**1,201,193,561**	**1,223,957,944**
142					
143		RAIL CARS			
144	312.11	Rail Cars - Flint Creek	6,725,198	3,015,416	3,070,319
145	312.11	Rail Cars - Welsh Plant	10,660,755	5,118,944	5,212,147
146			17,385,953	8,134,360	8,282,466
147					
148	310	Land - Coal Fired-Catahoula			
149	316	Misc Pwr Plant Equip-Coal- Alliance NE			
150					
151		Total Steam Production Plant	4,598,924,991	1,462,760,251	1,490,287,104
152					
153		Other Production Plant			
154					
155		MATTISON			
156	340	Land	1,451,852	-	-
157	341	Structures & Improvements	35,218,126	8,854,230	9,015,443

Southwestern Electric Power Company
Partially Projected Test Year Depreciation Information
Test Year Ending December 31, 2018
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(1)	(2)	(3)	(4)	(5)	(6)	(7)
			PARTIALLY PROJECTED TEST YEAR			
Line No.	Acct. Number	Account Description	Plant Balance Per Book End of Historical Portion of Test Year (a)	Additions	Projected Retirements	Reclassification
158	343	Prime Movers	-			
159	344	Generators	84,008,692	1,072,538	(337,730)	
160	345	Accessory Electrical Equip.	8,994,738	114,835	(36,159)	
161	346	Misc Power Plant Equip	784,464	10,015	(3,155)	
162		Total	130,152,498	1,643,117	(517,398)	
163						
164						
165		Total Other Production Plant	130,152,498	1,643,117	(517,398)	
166		Generation RWIP				
167		**Total Production Plant(b)**	**4,689,718,034**	**59,092,868**	**(18,607,694)**	
168						
169		TRANSMISSION PLANT (b)				
170						
171	350.0	Land	4,775,088			
172	350.1	Land Rights	92,545,875	2,326,710	(94,480.00)	
173	352.0	Structures & Improvements	14,717,825	370,024	(15,025.00)	
174	353.0	Station Equipment	619,251,082	15,568,687	(632,201.00)	
175	354.0	Towers & Fixtures	40,872,806	1,027,591	(41,730.00)	
176	355.0	Poles & Fixtures	647,359,524	16,275,366	(660,900.00)	
177	356.0	OH Conductor & Devices	369,022,084	9,289,374	(388,470.00)	
178	356.16	OVH Cond-Dev-Smart Grid	11,491,174	277,170		
179	357.0	Underground Conduit	2,069,255	52,022	(2,115.00)	
180	358.0	Underground Conductor & Devices	295			
181	358.16	Ug Cond-Dev-Smart Grid	40,046	1,007	(40.00)	
182	359.0	Roads and Trails	131,947			
183						
184		**Total Transmission Plant**	**1,802,277,001**	**45,187,951**	**(1,834,961)**	
185						
186						
187		DISTRIBUTION PLANT				
188						

SCHEDULE F-1.2

Southwestern Electric Power Company
Partially Projected Test Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

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(1) Line No.	(2) Acct. Number	(3) Account Description	(8) Projected Plant Balance End of Test Year (A)	(9) Accumulated Depreciation Per Book End of Historical Portion of Test Year	(10) Accumulated Depreciation @ December 31, 2018
158	343	Prime Movers	-		
159	344	Generators	84,743,499	22,068,076	22,469,880
160	345	Accessory Electrical Equip.	9,073,414	1,519,685	1,547,354
161	346	Misc Power Plant Equip	791,326	113,843	115,915
162		Total	131,278,217	32,555,834	33,148,592
163					
164					
165		Total Other Production Plant	131,278,217	32,555,834	33,148,592
166		Generation RWIP			(6,640,652)
167		**Total Production Plant(b)**	**4,730,203,208**	**1,495,316,085**	**1,516,795,044**
168					
169		TRANSMISSION PLANT (b)			
170					
171	350.0	Land	4,775,088		
172	350.1	Land Rights	94,778,105	27,254,614	27,750,850
173	352.0	Structures & Improvements	15,072,824	5,575,898	5,677,407
174	353.0	Station Equipment	634,187,568	171,470,536	174,592,108
175	354.0	Towers & Fixtures	41,858,667	27,834,357	28,341,074
176	355.0	Poles & Fixtures	662,973,990	161,698,937	164,642,617
177	356.0	OH Conductor & Devices	377,922,988	124,746,362	127,017,332
178	356.16	OVH Cond-Dev-Smart Grid	11,768,344		
179	357.0	Underground Conduit	2,119,162	12,914	13,149
180	358.0	Underground Conductor & Devices	295	574	587
181	358.16	Ug Cond-Dev-Smart Grid	41,013		
182	359.0	Roads and Trails	131,947	94,673	96,397
183					
184		**Total Transmission Plant**	**1,845,629,991**	**518,688,866**	**528,131,521**
185					
186					
187		DISTRIBUTION PLANT			
188					

Southwestern Electric Power Company
Partially Projected Test Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

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(1)	(2)	(3)	PARTIALLY PROJECTED TEST YEAR (4)	(5)	(6)	(7)
Line No.	Acct. Number	Account Description	Plant Balance Per Book End of Historical Portion of Test Year (a)	Additions	Projected Retirements	Reclassification
189	360.0	Land	7,826,063	0	0	
190	360.1	Land Rights	3,593,142	0	0	
191	361.0	Structures & Improvements	7,775,648	252,037	(34,750)	
192	362.0	Station Equipment	307,422,114	9,964,645	(1,373,965)	
193	364.0	Poles, Towers, & Fixtures	438,848,632	14,224,642	(1,961,355)	
194	365.0	Overhead Conductor & Devices	439,915,586	14,259,229	(1,966,125)	
195	366.0	Underground Conduit	66,522,478	2,156,230	(297,310)	
196	367.0	Underground Conductor	219,395,395	7,111,385	(980,550)	
197	368.0	Line Transformers	386,576,527	12,530,321	(1,727,735)	
198	369.0	Services	90,906,356	2,946,599	(406,290)	
199	370.0	Meters	84,378,024	2,734,991	(377,115)	
200	371.0	Installations on Custs. Prem.	43,598,031	1,413,168	(194,855)	
201	373.0	Street Lighting & Signal Sys.	41,871,653	1,357,210	(187,140)	
202						
203		**Total Distribution Plant (b)**	**2,138,629,650**	**68,950,457**	**(9,507,190)**	
204						
205						
206						
207		GENERAL PLANT				
208	389.0	Land	18,643,207	0	0	
209	390.0	Structures & Improvements	104,459,189	1,210,106	(777,556)	
210	391.0	Office Furniture & Equipment	9,989,968	515	(515)	
211	391.11	Office Equipment - Computers	69,159	286		
212	392.0	Transportation Equipment (1)	4,118,518	0	0	
213	393.0	Stores Equipment	2,994,676	34,692	(22,290)	
214	394.0	Tools Shop & Garage Equipment	26,341,827	305,157	(196,080)	
215	395.0	Laboratory Equipment	5,501,275	0	0	
216	396.0	Power Operated Equipment	759,763	0	0	
217	397.0	Communication Equipment	33,064,030	404,399	(267,485)	
218	397.11	Communication Equipment	347,494			
219	397.12	Communication Equipment	2,434,611	10,081		

SCHEDULE F-1.2

Southwestern Electric Power Company
Partially Projected Test Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

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(1) Line No.	(2) Acct. Number	(3) Account Description		(8) Projected Plant Balance End of Test Year (A)	(9) Accumulated Depreciation Per Book End of Historical Portion of Test Year	(10) Accumulated Depreciation @ December 31, 2018
189	360.0	Land		7,826,063		
190	360.1	Land Rights		3,593,142	2,364,869.00	2,407,927
191	361.0	Structures & Improvements		7,992,935	2,358,032.17	2,400,959
192	362.0	Station Equipment		316,012,794	87,227,172.25	88,815,121
193	364.0	Poles, Towers, & Fixtures		451,111,919	191,771,136.17	195,262,268
194	365.0	Overhead Conductor & Devices		452,208,690	154,898,443.43	157,718,325
195	366.0	Underground Conduit		68,381,398	25,318,278.45	25,779,190
196	367.0	Underground Conductor		225,526,230	98,679,999.24	100,476,439
197	368.0	Line Transformers		397,379,113	119,257,576.27	121,428,624
198	369.0	Services		93,446,665	39,223,885.30	39,937,945
199	370.0	Meters		86,735,900	(40,093,369.52)	(40,823,256)
200	371.0	Installations on Custs. Prem.		44,816,344	25,160,367.29	25,618,404
201	373.0	Street Lighting & Signal Sys.		43,041,723	25,627,015.24	26,093,546
202						
203		**Total Distribution Plant (b)**		**2,198,072,917**	**731,793,405**	**745,115,493**
204						
205						
206						
207		GENERAL PLANT				
208	389.0	Land		18,643,207	(192,917)	(196,427)
209	390.0	Structures & Improvements		104,891,739	42,854,248	43,634,396
210	391.0	Office Furniture & Equipment		9,989,968	6,516,539	6,591,599
211	391.11	Office Equipment - Computers		69,445		
212	392.0	Transportation Equipment	(1)	4,118,518	3,669,673	3,736,339
213	393.0	Stores Equipment		3,007,078	1,704,196	1,735,220
214	394.0	Tools Shop & Garage Equipment		26,450,904	8,940,550	9,103,313
215	395.0	Laboratory Equipment		5,501,275	5,426,186	5,455,372
216	396.0	Power Operated Equipment		759,763	30,497	31,052
217	397.0	Communication Equipment		33,200,944	17,558,662	17,860,569
218	397.11	Communication Equipment		347,494		
219	397.12	Communication Equipment		2,444,692		

Southwestern Electric Power Company
Partially Projected Test Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: This schedule shows original cost of utility plant in service and accumulated depreciation by account, subtotaled by function, for a partially projected test year. Schedule F-1.2 should only be completed if the company is filing a partially projected test year. Total amounts must reconcile to the recap schedules indicated.

PARTIALLY PROJECTED TEST YEAR

(1) Line No.	(2) Acct. Number	(3) Account Description		(4) Plant Balance Per Book End of Historical Portion of Test Year (a)	(5) Additions	(6) Projected Retirements	(7) Reclassification
220	397.13	Communication Equipment		558,176	1,808		
221	398.0	Miscellaneous Equipment		2,596,116	30,076	(19,325)	
222	399.0	Fuel Related Assets-Lignite	(2)	65,797,751	773,030	(496,715)	
223	399.10	Fuel Related Assets-Lignite	(2)	19,880			
224	399.3	Alliance Rail Facility		22,606,789			
225	399.19	ARO - Office Bldgs.		932,028			
226		**Total General Plant (b)**		**301,234,453**	**2,770,150**	**(1,779,966)**	
227							
228		AFUDC Generation					
229		AFUDC Transmission					
230		AFUDC Distribution					
231		AFUDC Fuel					
232		AFUDC General					
233		Total AFUDC					
234							
235		**Total Plant A/C 101 & 106**		**9,029,529,860**	**208,664,793**	**(39,827,811)**	

Support Schedules
(a) E-17 Part II A

Southwestern Electric Power Company
Partially Projected Test Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: This schedule shows original cost of utility plant in service and accumulated depreciation by account, subtotaled by function, for a partially projected test year. Schedule F-1.2 should only be completed if the company is filing a partially projected test year. Total amounts must reconcile to the recap schedules indicated.

(1) Line No.	(2) Acct. Number	(3) Account Description		(8) Projected Plant Balance End of Test Year (A)	(9) Accumulated Depreciation Per Book End of Historical Portion of Test Year	(10) Accumulated Depreciation @ December 31, 2018
220	397.13	Communication Equipment		559,984		
221	398.0	Miscellaneous Equipment		2,606,867	1,278,589	1,301,135
222	399.0	Fuel Related Assets-Lignite	(2)	66,074,066	74,822,846	76,120,668
223	399.10	Fuel Related Assets-Lignite	(2)	19,880		
224	399.3	Alliance Rail Facility		22,606,789		
225	399.19	ARO - Office Bldgs.		932,028		
226		**Total General Plant (b)**		**302,224,637**	**162,609,067**	**165,373,236**
227						
228		AFUDC Generation				
229		AFUDC Transmission				
230		AFUDC Distribution				
231		AFUDC Fuel				
232		AFUDC General				
233		Total AFUDC				
234						
235		**Total Plant A/C 101 & 106**		**9,198,366,841**	**2,958,424,408**	**3,006,387,924**

Support Schedules
(a) E-17 Part II A

Support Schedules
(A) F-1.3

Southwestern Electric Power Company
Pro Forma Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

PRO FORMA YEAR

Explanation: This schedule shows actual and proposed rates of depreciation expense, original cost of utility plant in service and accumulated depreciation by account, subtotaled by function, for the pro forma year. Total amounts must reconcile to the recap schedules indicated. If changes to existing depreciation rates are requested, columns 11 and 13 must be completed and the company must provide, as set forth in Section 8 of the Rules of Practice and Procedure, a comprehensive depreciation study which addresses life and salvage estimates in support of such new rates.

(1)	(2)	(3)	(4)	(5)a	(5)b	(6)	(7)
				Pro Forma Adjustments			
Line No.	Acct. Number	Acct. Description	Plant Balance Beginning of Pro Forma Year (a) (A)	Additions (c)	Additions(b)	Retirements (b)	Reclassifications(d)
		INTANGIBLE PLANT					
1	301	Organization	12,202				
2	302	Franchise and Consents					
3	303	Miscellaneous Intangible Plant-Software	122,223,886		39,885,556	(12,159,000)	
4		**TOTAL INTANGIBLE PLANT**	**122,236,088**	**-**	**39,885,556**	**(12,159,000)**	**-**
5		Reclassed Generation CWIP In-service at Pro-forma Year End					7,584,352
6		**TOTAL INTANGIBLE PLANT**	**122,236,088**	**-**	**39,885,556**	**(12,159,000)**	**7,584,352**
		STEAM PRODUCTION PLANT					
		Gas & Oil Plants					
		ARSENAL HILL					
7	310.3	Land Oil/Gas	370,798		-	-	
8	311.3	Structures & Improvements	5,798,815		-	-	
9	312.3	Boiler Plant Equipment	6,938,642		123,944	(61,344)	
10	314.3	Turbogenerator Units	4,835,133		86,369	(42,748)	
11	315.3	Accessory Electrical Equipment	1,224,353		21,871	(10,825)	
12	316.3	Misc. Power Plant Equip. Oil-Gas	7,114,514		127,086	(62,900)	
13	317.3	ARO Steam Prod Plt Oil/Gas	507,714		-	-	
14		Total	26,789,969	-	359,270	(177,817)	-
		KNOX LEE					
15	310.3	Land Oil/Gas	102,781		-	-	
16	311.3	Structures & Improvements	8,397,844		115,960	(57,393)	
17	312.3	Boiler Plant Equipment	35,791,395		494,218	(244,607)	
18	314.3	Turbogenerator Units	21,971,898		303,395	(150,162)	
19	315.3	Accessory Electrical Equipment	4,092,547		56,511	(27,970)	
20	316.3	Misc. Power Plant Equip.	1,893,801		26,150	(12,943)	
21	317.3	ARO Steam Prod Plt Oil/Gas	2,036,608	-			-
22		Total	74,286,874	-	996,234	(493,075)	-

Support Schedules
(a) F-1.2
(b) WP B 2-4
(c) B-2
(d) WP B 2-7
(e) E-17 Part II A
(f) WP B-2-6

Recap Schedules
(A) WP B 2-4
(B) WP C 2-14

SCHEDULE F-1.3

Southwestern Electric Power Company
Pro Forma Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

PRO FORMA YEAR

(1) Line No.	(2) Acct. Number	(3) Acct. Description	(8) Plant Balance End of Pro Forma Year (A)(d) (e)	(9) Pro Forma Year End Accum. Depreciation (f)	(10) Accrual Rates Present	(11) Accrual Rates Proposed	(12) Annual Expense Present (B) (Col. 8 * Col. 10)	(13) Annual Expense Proposed (B) (Col. 8 * Col. 11)
		INTANGIBLE PLANT						
1	301	Organization	12,202	0			-	-
2	302	Franchise and Consents						
3	303	Miscellaneous Intangible Plant-Software	149,950,443	53,806,366			17,638,899	19,016,076
							-	-
4		**TOTAL INTANGIBLE PLANT**	**149,962,645**	**53,806,366**			**17,638,899**	**19,016,076**
5		Reclassed Generation CWIP In-service at	7,584,352					961,737
6		**TOTAL INTANGIBLE PLANT**	**157,546,997**	**53,806,366**			**17,638,899**	**19,977,813**
		STEAM PRODUCTION PLANT						
		Gas & Oil Plants						
		ARSENAL HILL						
7	310.3	Land Oil/Gas	370,798	-	0.00%	0.00%	-	-
8	311.3	Structures & Improvements	5,798,815	5,700,944	1.18%	2.72%	68,426	157,612
9	312.3	Boiler Plant Equipment	7,001,242	6,369,984	0.94%	3.29%	65,812	230,483
10	314.3	Turbogenerator Units	4,878,754	4,667,496	0.92%	2.48%	44,885	120,877
11	315.3	Accessory Electrical Equipment	1,235,399	767,424	1.66%	3.91%	20,508	48,284
12	316.3	Misc. Power Plant Equip. Oil-Gas	7,178,700	4,757,578	2.75%	6.70%	197,414	480,616
13	317.3	ARO Steam Prod Plt Oil/Gas	507,714	279,562	3.03%		15,384	16,832
14		Total	26,971,422	22,542,988			412,428	1,054,705
		KNOX LEE						
15	310.3	Land Oil/Gas	102,781	-	0.00%	0.00%	-	-
16	311.3	Structures & Improvements	8,456,411	8,209,000	0.43%	2.62%	36,363	221,830
17	312.3	Boiler Plant Equipment	36,041,006	32,924,676	0.44%	3.23%	158,580	1,165,903
18	314.3	Turbogenerator Units	22,125,131	19,653,946	0.56%	2.90%	123,901	641,430
19	315.3	Accessory Electrical Equipment	4,121,088	2,979,658	0.95%	3.60%	39,150	148,309
20	316.3	Misc. Power Plant Equip.	1,907,008	1,794,343	0.42%	4.75%	8,009	90,626
21	317.3	ARO Steam Prod Plt Oil/Gas	2,036,608	1,132,585	3.03%		366,003	58,707
22		Total	74,790,033	66,694,208			732,007	2,326,805

Support Schedules
(a) F-1.2
(b) WP B 2-4
(c) B-2
(d) WP B 2-7
(e) E-17 Part II A
(f) WP B-2-6

Recap Schedules
(A) WP B 2-4
(B) WP C 2-14

SCHEDULE F-1.3

Southwestern Electric Power Company
Pro Forma Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: This schedule shows actual and proposed rates of depreciation expense, original cost of utility plant in service and accumulated depreciation by account, subtotaled by function, for the pro forma year. Total amounts must reconcile to the recap schedules indicated. If changes to existing depreciation rates are requested, columns 11 and 13 must be completed and the company must provide, as set forth in Section 8 of the Rules of Practice and Procedure, a comprehensive depreciation study which addresses life and salvage estimates in support of such new rates.

PRO FORMA YEAR

(1)	(2)	(3)	(4)	(5)a	(5)b	(6)	(7)
				Pro Forma Adjustments			
Line No.	Acct. Number	Acct. Description	Plant Balance Beginning of Pro Forma Year (a) (A)	Additions (c)	Additions(b)	Retirements (b)	Reclassifications(d)
		LIEBERMAN					
23	310.3	Land Oil/Gas	24,026		-	-	
24	311.3	Structures & Improvements	3,829,290		-	-	
25	312.3	Boiler Plant Equipment	18,657,360		337,941	(167,260)	
26	314.3	Turbogenerator Units	11,815,404		214,012	(105,923)	
27	315.3	Accessory Electrical Equipment	3,431,323		-	-	
28	316.3	Misc. Power Plant Equip.	2,137,095		-	-	
29	317.3	ARO Steam Prod Plt Oil/Gas	1,263,344		-	-	
30		Total	41,157,842	-	551,953	(273,183)	-
		LONE STAR					
31	310	Land Oil/Gas	58,487		-	-	
32	311.0	Structures & Improvements	934,757		-	-	
33	312.0	Boiler Plant Equipment	4,148,920		70,729	-	
34	314.0	Turbogenerator Units	2,586,137		44,087	-	
35	315.0	Accessory Electrical Equipment	879,417		-	-	
36	316.0	Misc. Power Plant Equip.	201,389		-	-	
37	317	ARO Steam Prod Plt Oil/Gas	123,591		-	-	
38		Total	8,932,698	-	114,816	-	-
		WILKES					
39	310	Land Oil/Gas	443,729		-	-	
40	311.0	Structures & Improvements	7,921,771		108,648	(53,774)	
41	312.0	Boiler Plant Equipment	47,594,111		652,760	(323,075)	
42	314.0	Turbogenerator Units	38,162,689		523,406	(259,054)	
43	315.0	Accessory Electrical Equipment	10,236,269		140,392	(69,485)	
44	316.0	Misc. Power Plant Equip.	9,122,818		125,121	(61,927)	
45	317	ARO Steam Prod Plt Oil/Gas	2,122,856		-	-	
46		Total	115,604,243	-	1,550,327	(767,315)	-
		STALL					
47	310	Land Oil/Gas					
48	311.0	Structures & Improvements	53,747,621		720,789	(356,747)	
49	312.0	Boiler Plant Equipment	87,936,702		1,179,287	(583,675)	
50	314.0	Turbogenerator Units	170,469,967		2,286,109	(1,131,484)	
51	315.0	Accessory Electrical Equipment	40,678,082		545,519	(269,998)	

Support Schedules
(a) F-1.2
(b) WP B 2-4
(c) B-2
(d) WP B 2-7
(e) E-17 Part II A
(f) WP B-2-6

Recap Schedules
(A) WP B 2-4
(B) WP C 2-14

SCHEDULE F-1.3

Southwestern Electric Power Company
Pro Forma Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

PRO FORMA YEAR

(1) Line No.	(2) Acct. Number	(3) Acct. Description	(8) Plant Balance End of Pro Forma Year (A)(d) (e)	(9) Pro Forma Year End Accum. Depreciation (f)	(10) Accrual Rates Present	(11) Accrual Rates Proposed	(12) Annual Expense Present (B) (Col. 8 * Col. 10)	(13) Annual Expense Proposed (B) (Col. 8 * Col. 11)
		LIEBERMAN						
23	310.3	Land Oil/Gas	24,026	-	0.00%	0.00%	-	-
24	311.3	Structures & Improvements	3,829,290	4,121,009	0.85%	2.46%	32,549	94,061
25	312.3	Boiler Plant Equipment	18,828,041	18,367,234	0.78%	3.35%	146,859	631,561
26	314.3	Turbogenerator Units	11,923,493	11,690,877	0.18%	2.83%	21,462	337,991
27	315.3	Accessory Electrical Equipment	3,431,323	2,372,158	0.56%	3.67%	19,215	126,008
28	316.3	Misc. Power Plant Equip.	2,137,095	1,877,472	2.67%	6.89%	57,060	147,143
29	317.3	ARO Steam Prod Plt Oil/Gas	1,263,344	861,893	3.03%		38,279	79,033
30		Total	41,436,612	39,290,643			315,425	1,415,797
		LONE STAR						
31	310	Land Oil/Gas	58,487	-	0.00%	0.00%	-	-
32	311.0	Structures & Improvements	934,757	901,736	0.94%	5.05%	8,787	47,248
33	312.0	Boiler Plant Equipment	4,219,649	3,280,304	0.97%	6.44%	40,931	271,607
34	314.0	Turbogenerator Units	2,630,224	2,469,247	0.96%	5.35%	25,250	140,803
35	315.0	Accessory Electrical Equipment	879,417	570,616	2.65%	7.71%	23,305	67,796
36	316.0	Misc. Power Plant Equip.	201,389	108,680	4.36%	14.93%	8,781	30,064
37	317	ARO Steam Prod Plt Oil/Gas	123,591	125,241	3.03%		3,745	7,692
38		Total	9,047,514	7,455,824			110,797	565,209
		WILKES						
39	310	Land Oil/Gas	443,729	-	0.00%	0.00%	-	-
40	311.0	Structures & Improvements	7,976,646	7,752,141	0.85%	2.18%	67,801	173,828
41	312.0	Boiler Plant Equipment	47,923,795	31,935,532	0.78%	2.88%	373,806	1,381,045
42	314.0	Turbogenerator Units	38,427,041	29,322,686	0.81%	2.63%	311,259	1,010,381
43	315.0	Accessory Electrical Equipment	10,307,177	4,710,032	2.37%	3.82%	244,280	393,707
44	316.0	Misc. Power Plant Equip.	9,186,011	3,574,443	0.05%	4.83%	4,593	443,884
45	317	ARO Steam Prod Plt Oil/Gas	2,122,856	777,044	3.03%		64,323	111,479
46		Total	116,387,255	78,071,878			1,066,062	3,514,325
		STALL						
47	310	Land Oil/Gas		-	0.00%	0.00%	-	-
48	311.0	Structures & Improvements	54,111,663	12,740,180	2.86%	3.00%	1,547,594	1,622,838
49	312.0	Boiler Plant Equipment	88,532,314	13,940,129	2.86%	3.08%	2,532,024	2,729,813
50	314.0	Turbogenerator Units	171,624,593	2,167,767	2.86%	3.44%	4,908,463	5,895,884
51	315.0	Accessory Electrical Equipment	40,953,603	9,445,937	2.86%	3.03%	1,171,273	1,240,029

Support Schedules
(a) F-1.2
(b) WP B 2-4
(c) B-2
(d) WP B 2-7
(e) E-17 Part II A
(f) WP B-2-6

Recap Schedules
(A) WP B 2-4
(B) WP C 2-14

Southwestern Electric Power Company
Pro Forma Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

PRO FORMA YEAR

Explanation: This schedule shows actual and proposed rates of depreciation expense, original cost of utility plant in service and accumulated depreciation by account, subtotaled by function, for the pro forma year. Total amounts must reconcile to the recap schedules indicated. If changes to existing depreciation rates are requested, columns 11 and 13 must be completed and the company must provide, as set forth in Section 8 of the Rules of Practice and Procedure, a comprehensive depreciation study which addresses life and salvage estimates in support of such new rates.

(1)	(2)	(3)	(4)	(5)a	(5)b	(6)	(7)
				Pro Forma Adjustments			
Line No.	Acct. Number	Acct. Description	Plant Balance Beginning of Pro Forma Year (a) (A)	Additions (c)	Additions(b)	Retirements (b)	Reclassifications(d)
52	316.0	Misc. Power Plant Equip.	85,428,034		1,145,644	(567,024)	
53	317	ARO Steam Prod Plt Oil/Gas	-				
54		Total	438,260,406	-	5,877,348	(2,908,928)	-
55		Total Gas & Oil Plants	**705,032,032**	**-**	**9,449,948**	**(4,620,318)**	**-**
		Coal and Lignite Plants					
		DOLET HILLS					
56	310	Land - Coal	1,510,615		-	-	
57	311.0	Structures & Improvements	56,678,577		766,102	(379,174)	
58	312.0	Boiler Plant Equipment	221,858,121		2,998,766	(1,484,206)	
59	314.0	Turbogenerator Units	39,988,064		540,503	(267,516)	
60	315.0	Accessory Electrical Equipment	12,146,164		164,175	(81,257)	
61	316.0	Misc. Power Plant Equip.	16,246,032		219,591	(108,684)	
62	317	Dolet Hills Generating ARO Ash Pond : S	1,230,658		-	-	
63	317	Dolet Hills Generating Plant : SEP : PPDLH					
64		Total	349,658,231	-	4,689,137	(2,320,837)	-
		FLINT CREEK					
65	310	Land	3,364,925		-	-	
66	311.0	Structures & Improvements	27,003,982		382,339	(189,234)	
67	312.0	Boiler Plant Equipment	297,738,988		4,215,568	(2,086,449)	
68	314.0	Turbogenerator Units	15,431,977		218,495	(108,142)	
69	315.0	Accessory Electrical Equipment	8,863,884		125,500	(62,115)	
70	316.0	Misc. Power Plant Equip.	6,129,876		86,790	(42,956)	
71	317	ARO#1 Flint Creek Ash Pond : SEP : PPF	9,719,253		-	-	
72	317	ARO#2 Flint Creek Ash Pond : SEP : PPFLCARO2					
73	317	ARO#3 Flint Creek Ash Pond : SEP : PPFLCARO3					
74	317	Flint Creek Generating Plant : SEP : PPFLC					
75		Total	368,252,885	-	5,028,692	(2,488,896)	-
		PIRKEY					
76	310	Land	5,843,029		-	-	
77	311.0	Structures & Improvements	108,542,725		-	-	
78	312.0	Boiler Plant Equipment	372,761,096		7,268,071	(3,597,252)	
79	314.0	Turbogenerator Units	50,945,628		-	-	

Support Schedules
(a) F-1.2
(b) WP B 2-4
(c) B-2
(d) WP B 2-7
(e) E-17 Part II A
(f) WP B-2-6

Recap Schedules
(A) WP B 2-4
(B) WP C 2-14

Southwestern Electric Power Company
Pro Forma Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

PRO FORMA YEAR

(1) Line No.	(2) Acct. Number	(3) Acct. Description	(8) Plant Balance End of Pro Forma Year (A)(d) (e)	(9) Pro Forma Year End Accum. Depreciation (f)	(10) Accrual Rates Present	(11) Accrual Rates Proposed	(12) Annual Expense Present (B) (Col. 8 * Col. 10)	(13) Annual Expense Proposed (B) (Col. 8 * Col. 11)
52	316.0	Misc. Power Plant Equip.	86,006,653	20,003,966	2.86%	3.02%	2,459,790	2,596,717
53	317	ARO Steam Prod Plt Oil/Gas			3.03%		-	-
54		Total	441,228,826	58,297,979			12,619,144	14,085,281
55		Total Gas & Oil Plants	**709,861,662**	**272,353,520**			**15,255,864**	**22,962,121**
		Coal and Lignite Plants						
		DOLET HILLS						
56	310	Land - Coal	1,510,615	9,534	0.00%	0.00%	-	-
57	311.0	Structures & Improvements	57,065,505	50,982,385	0.88%	1.98%	502,176	1,130,852
58	312.0	Boiler Plant Equipment	223,372,681	128,999,732	1.06%	2.44%	2,367,750	5,442,174
59	314.0	Turbogenerator Units	40,261,051	31,660,167	0.89%	2.16%	358,323	870,301
60	315.0	Accessory Electrical Equipment	12,229,082	9,985,517	0.85%	2.13%	103,947	260,054
61	316.0	Misc. Power Plant Equip.	16,356,939	12,629,863	1.41%	2.28%	230,633	372,172
62	317	Dolet Hills Generating ARO Ash Pond : SI	1,230,658	318,918	3.03%		37,289	32,843
63	317	Dolet Hills Generating Plant : SEP : PPDL			3.03%		-	-
64		Total	352,026,531	234,586,116			3,600,119	8,108,396
		FLINT CREEK						
65	310	Land	3,364,925	-	0.00%	0.00%	-	-
66	311.0	Structures & Improvements	27,197,087	17,296,630	1.70%	2.37%	462,350	643,291
67	312.0	Boiler Plant Equipment	299,868,107	49,703,428	1.45%	4.03%	4,348,088	12,093,159
68	314.0	Turbogenerator Units	15,542,330	9,097,869	1.40%	2.59%	217,593	402,290
69	315.0	Accessory Electrical Equipment	8,927,269	5,225,707	1.54%	2.62%	137,480	234,114
70	316.0	Misc. Power Plant Equip.	6,173,710	3,674,657	2.20%	2.78%	135,822	171,684
71	317	ARO#1 Flint Creek Ash Pond : SEP : PPF	9,719,253	1,766,934	3.03%		294,493	-
72	317	ARO#2 Flint Creek Ash Pond : SEP : PPF			3.03%		-	-
73	317	ARO#3 Flint Creek Ash Pond : SEP : PPF			3.03%		-	-
74	317	Flint Creek Generating Plant : SEP : PPFL			3.03%		-	-
75		Total	370,792,681	86,765,225			5,595,826	13,544,538
		PIRKEY						
76	310	Land	5,843,028	-	0.00%	0.00%	-	-
77	311.0	Structures & Improvements	108,542,725	106,121,528	0.89%	1.96%	966,030	2,122,624
78	312.0	Boiler Plant Equipment	376,431,917	254,228,783	1.13%	2.36%	4,253,681	8,895,399
79	314.0	Turbogenerator Units	50,945,628	51,222,326	0.85%	1.98%	433,038	1,010,153

Support Schedules
(a) F-1.2
(b) WP B 2-4
(c) B-2
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(e) E-17 Part II A
(f) WP B-2-6

Recap Schedules
(A) WP B 2-4
(B) WP C 2-14

SCHEDULE F-1.3

Southwestern Electric Power Company
Pro Forma Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: This schedule shows actual and proposed rates of depreciation expense, original cost of utility plant in service and accumulated depreciation by account, subtotaled by function, for the pro forma year. Total amounts must reconcile to the recap schedules indicated. If changes to existing depreciation rates are requested, columns 11 and 13 must be completed and the company must provide, as set forth in Section 8 of the Rules of Practice and Procedure, a comprehensive depreciation study which addresses life and salvage estimates in support of such new rates.

PRO FORMA YEAR

(1)	(2)	(3)	(4)	(5)a	(5)b	(6)	(7)
				Pro Forma Adjustments			
Line No.	Acct. Number	Acct. Description	Plant Balance Beginning of Pro Forma Year (a) (A)	Additions (c)	Additions(b)	Retirements (b)	Reclassifications(d)
80	315.0	Accessory Electrical Equipment	18,277,191		356,367	(176,380)	
81	316.0	Misc. Power Plant Equip.	18,679,619		364,214	(180,264)	
82	317	ARO#1 Pirkey Ash Pond - TX SEP	20,646,276		-	-	
83	317	ARO#2 Pirkey Ash Pond - TX SEP					
84	317	ARO#3 Pirkey Ash Pond - TX SEP					
85	317	ARO#4 Pirkey Ash Pond - TX SEP					
86	317	ARO#5 Pirkey Ash Pond - TX SEP					
87	317	ARO#6 Pirkey Ash Pond - TX SEP					
88	317	Pirkey Generating Plant : SEP : PPPRK					
89		Total	595,695,564	-	7,988,652	(3,953,896)	-
		WELSH					
90	310	Land	1,895,473		-	-	
91	311.0	Structures & Improvements	72,805,953		999,773	(494,827)	
92	312.0	Boiler Plant Equipment	582,836,369		8,003,524	(3,961,255)	
93	314.0	Turbogenerator Units	142,866,540		1,961,847	(970,994)	
94	315.0	Accessory Electrical Equipment	46,095,197		632,980	(313,287)	
95	316.0	Misc. Power Plant Equip.	21,403,344		293,911	(145,468)	
96	317	ARO#1 Welsh Landfill : SEP : PPWSHAF	19,114,678		-	-	
97	317	ARO#2 Welsh Landfill : SEP : PPWSHARO2			-	-	
98	317	ARO#3 Welsh Landfill : SEP : PPWSHARO3					
99	317	ARO#4 Welsh Landfill : SEP : PPWSHARO4					
100	317	Welsh Generating Plant : SEP : PPWSH					
101		Total	887,017,554	-	11,892,035	(5,885,831)	-
		TURK					
102	310	Land	11,468,899		-	-	
103	310.1	Land Rights-coal	1,886,717		-	-	
104	311.0	Structures & Improvements	288,505,241		4,541,453	(2,247,742)	
105	312.0	Boiler Plant Equipment	996,430,785		15,685,134	(7,763,186)	
106	314.0	Turbogenerator Units	232,599,492		-	-	
107	315.0	Accessory Electrical Equipment	94,305,219		1,484,489	(734,731)	
108	316.0	Misc. Power Plant Equip.	48,507,106		763,566	(377,918)	
109	317	ARO#1 Turk Landfill : SEP : JWTGPARO	2,179,313		-	-	
110		Total	1,675,882,772	-	22,474,642	(11,123,577)	-

Support Schedules
(a) F-1.2
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(e) E-17 Part II A
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Recap Schedules
(A) WP B 2-4
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SCHEDULE F-1.3

Southwestern Electric Power Company
Pro Forma Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

PRO FORMA YEAR

(1) Line No.	(2) Acct. Number	(3) Acct. Description	(8) Plant Balance End of Pro Forma Year (A)(d) (e)	(9) Pro Forma Year End Accum. Depreciation (f)	(10) Accrual Rates Present	(11) Accrual Rates Proposed	(12) Annual Expense Present (B) (Col. 8 * Col. 10)	(13) Annual Expense Proposed (B) (Col. 8 * Col. 11)
80	315.0	Accessory Electrical Equipment	18,457,178	13,890,802	1.09%	2.23%	201,183	411,102
81	316.0	Misc. Power Plant Equip.	18,863,568	16,519,821	1.16%	2.15%	218,817	406,136
82	317	ARO#1 Pirkey Ash Pond - TX SEP	20,646,276	2,664,257	3.03%		625,582	667,246
83	317	ARO#2 Pirkey Ash Pond - TX SEP			3.03%		-	-
84	317	ARO#3 Pirkey Ash Pond - TX SEP			3.03%		-	-
85	317	ARO#4 Pirkey Ash Pond - TX SEP			3.03%		-	-
86	317	ARO#5 Pirkey Ash Pond - TX SEP			3.03%		-	-
87	317	ARO#6 Pirkey Ash Pond - TX SEP			3.03%		-	-
88	317	Pirkey Generating Plant : SEP : PPPRK			3.03%		-	-
89		Total	599,730,320	444,647,517			6,698,332	13,512,660
		WELSH						
90	310	Land	1,895,473	-	0.00%	0.00%	-	-
91	311.0	Structures & Improvements	73,310,899	42,855,110	1.67%	2.39%	1,224,292	1,752,701
92	312.0	Boiler Plant Equipment	586,878,638	180,760,186	1.77%	3.46%	10,387,752	20,292,738
93	314.0	Turbogenerator Units	143,857,393	62,309,421	1.61%	2.90%	2,316,104	4,175,732
94	315.0	Accessory Electrical Equipment	46,414,890	16,051,222	1.41%	3.18%	654,450	1,474,903
95	316.0	Misc. Power Plant Equip.	21,551,787	15,257,868	2.09%	3.05%	450,432	658,309
96	317	ARO#1 Welsh Landfill : SEP : PPWSHAF	19,114,678	2,947,679	3.03%		579,175	681,030
97	317	ARO#2 Welsh Landfill : SEP : PPWSHAR			3.03%		-	-
98	317	ARO#3 Welsh Landfill : SEP : PPWSHAR			3.03%		-	-
99	317	ARO#4 Welsh Landfill : SEP : PPWSHAR			3.03%		-	-
100	317	Welsh Generating Plant : SEP : PPWSH			3.03%		-	-
101		Total	893,023,758	320,181,486			15,612,205	29,035,413
		TURK						
102	310	Land	11,468,899	-	**N/A**	**N/A**	-	-
103	310.1	Land Rights-coal	1,886,717	-	**N/A**	**N/A**	-	-
104	311.0	Structures & Improvements	290,798,952	34,816,214	**2.07%**	**2.07%**	6,019,538	6,019,538
105	312.0	Boiler Plant Equipment	1,004,352,733	124,936,589	**2.07%**	**2.07%**	20,790,102	20,790,102
106	314.0	Turbogenerator Units	232,599,492	31,163,099	**2.07%**	**2.07%**	4,814,809	4,814,809
107	315.0	Accessory Electrical Equipment	95,054,977	11,836,356	**2.07%**	**2.07%**	1,967,638	1,967,638
108	316.0	Misc. Power Plant Equip.	48,892,754	5,293,631	**2.07%**	**2.07%**	1,012,080	1,012,080
109	317	ARO#1 Turk Landfill : SEP : JWTGPARO	2,179,313	312,626			38,150	38,150
110		Total	1,687,233,837	208,358,515			34,642,317	34,642,317

Support Schedules
(a) F-1.2
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(e) E-17 Part II A
(f) WP B-2-6

Recap Schedules
(A) WP B 2-4
(B) WP C 2-14

SCHEDULE F-1.3

Southwestern Electric Power Company
Pro Forma Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

PRO FORMA YEAR

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(1)	(2)	(3)	(4)	(5)a	(5)b	(6)	(7)
				Pro Forma Adjustments			
Line No.	Acct. Number	Acct. Description	Plant Balance Beginning of Pro Forma Year (a) (A)	Additions (c)	Additions(b)	Retirements (b)	Reclassifications(d)
111		**Total Coal and Lignite Plants**	**3,876,507,006**	**-**	**52,073,158**	**(25,773,037)**	**-**
		RAIL CARS					
112	312.11	Rail Cars - Flint Creek	6,725,198		-	-	
113	312.11	Rail Cars - Welsh Plant	10,660,755		146,394	(72,456)	
114			17,385,953	-	146,394	(72,456)	-
115	310	Land - Coal Fired-Catahoula					
116	316	Misc Pwr Plant Equip-Coal- Alliance NE					
			-	-	-	-	-
117		Steam Generation RWIP					
118		Total Steam Production Plant	**4,598,924,991**	**-**	**61,669,500**	**(30,465,811)**	**-**
		Other Production Plant					
		MATTISON					
119	340	Land	1,451,852		-	-	
120	341	Structures & Improvements	35,218,126		477,579	(236,373)	
121	343	Prime Movers					
122	344	Generators	84,743,499		1,149,172	(568,770)	
123	345	Accessory Electrical Equip.	9,073,414		123,041	(60,898)	
124	346	Misc Power Plant Equip	791,326		10,731	(5,311)	
125		Total	131,278,217	-	1,760,523	(871,352)	-
126		Other Generation RWIP					
127		Total Other Production Plant	**131,278,217**	**-**	**1,760,523**	**(871,352)**	**-**
128		**Total Production Plant**	**4,730,203,208**	**-**	**63,430,023**	**(31,337,163)**	**-**
129		Reclassed Generation CWIP In-service at Pro-forma Year End					14,439,547
130		**Adjusted Total Production Plant**	**4,730,203,208**	**-**	**63,430,023**	**(31,337,163)**	**14,439,547**
		TRANSMISSION PLANT					
131	350.0	Land	4,775,088				
132	350.1	Land Rights	94,778,104		8,703,878	(292,645)	
133	352.0	Structures & Improvements	15,072,822		1,384,202	(46,540)	
134	353.0	Station Equipment	634,187,567		58,240,153	(1,958,172)	(8,099,658)

Support Schedules
(a) F-1.2
(b) WP B 2-4
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(d) WP B 2-7
(e) E-17 Part II A
(f) WP B-2-6

Recap Schedules
(A) WP B 2-4
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SCHEDULE F-1.3

Southwestern Electric Power Company
Pro Forma Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

PRO FORMA YEAR

(1) Line No.	(2) Acct. Number	(3) Acct. Description	(8) Plant Balance End of Pro Forma Year (A)(d) (e)	(9) Pro Forma Year End Accum. Depreciation (f)	(10) Accrual Rates Present	(11) Accrual Rates Proposed	(12) Annual Expense Present (B) (Col. 8 * Col. 10)	(13) Annual Expense Proposed (B) (Col. 8 * Col. 11)
111		**Total Coal and Lignite Plants**	**3,902,807,127**	**1,294,538,859**			**66,148,798**	**98,843,324**
		RAIL CARS						
112	312.11	Rail Cars - Flint Creek	6,725,198	3,240,547	2.86%	2.69%	-	-
113	312.11	Rail Cars - Welsh Plant	10,734,693	5,501,122	2.43%	2.83%	-	-
114			17,459,891	8,741,669			-	-
115	310	Land - Coal Fired-Catahoula			0.00%	0.00%	-	-
116	316	Misc Pwr Plant Equip-Coal- Alliance NE					-	-
			-	-			-	-
117		Steam Generation RWIP		(6,745,090)				
118		Total Steam Production Plant	**4,630,128,680**	**1,568,888,958**			**81,404,662**	**121,805,445**
		Other Production Plant						
		MATTISON						
119	340	Land	1,451,852	-	0.00%	0.00%	-	-
120	341	Structures & Improvements	35,459,332	9,515,284	2.35%	2.38%	833,294	843,932
121	343	Prime Movers		-	0.00%	0.00%	-	-
122	344	Generators	85,323,902	23,715,672	2.36%	2.40%	2,013,644	2,049,342
123	345	Accessory Electrical Equip.	9,135,558	1,633,143	2.32%	2.78%	211,945	254,216
124	346	Misc Power Plant Equip	796,744	122,341	2.32%	2.74%	18,484	21,845
125		Total	132,167,388	34,986,440			3,077,368	3,169,335
126		Other Generation RWIP		(149,773)				
127		Total Other Production Plant	**132,167,388**	**34,836,667**			**3,077,368**	**3,169,335**
128		**Total Production Plant**	**4,762,296,068**	**1,603,725,625**			**84,482,030**	**124,974,780**
129		Reclassed Generation CWIP In-service at	14,439,547				-	433,935
130		**Adjusted Total Production Plant**	**4,776,735,615**	**1,603,725,625**			**84,482,030**	**125,408,716**
		TRANSMISSION PLANT						
131	350.0	Land	4,775,088	-	0.00%	0.00%	-	-
132	350.1	Land Rights	103,189,338	29,289,435	1.36%	1.44%	1,403,375	1,490,762
133	352.0	Structures & Improvements	16,410,486	5,992,193	1.39%	1.50%	228,106	245,700
134	353.0	Station Equipment	682,369,890	184,272,409	1.54%	1.59%	10,508,496	10,839,679

Support Schedules
(a) F-1.2
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Recap Schedules
(A) WP B 2-4
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SCHEDULE F-1.3

Southwestern Electric Power Company
Pro Forma Year Depreciation Information
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(1)	(2)	(3)	(4)	(5)a	(5)b	(6)	(7)
				Pro Forma Adjustments			
Line No.	Acct. Number	Acct. Description	Plant Balance Beginning of Pro Forma Year (a) (A)	Additions (c)	Additions(b)	Retirements (b)	Reclassifications(d)
135	354.0	Towers & Fixtures	41,858,668		3,844,060	(129,246)	
136	355.0	Poles & Fixtures	662,973,992		60,883,732	(2,047,055)	
137	356.0	OH Conductor & Devices	377,922,986		35,787,018	(1,203,244)	
138	356.16	OVH Cond-Dev-Smart Grid	11,768,344				
139	357.0	Underground Conduit	2,119,166		194,612	(6,543)	
140	358.0	Underground Conductor & Devices	295		3,766	(127)	
141	358.16	Ug Cond-Dev-Smart Grid	41,012				
142	359.0	Roads and Trails	131,947		0		
143		**Total Transmission Plant**	1,845,629,991	0	169,041,421	(5,683,572)	(8,099,658)
144		Reclassed Transmission CWIP In-service at Pro-forma Year End					16,184,668
145		**Adjusted Total Transmission Plant**	**1,845,629,991**	**0**	**169,041,421**	**(5,683,572)**	**8,085,010**
		DISTRIBUTION PLANT					
146	360.0	Land	7,826,063				
147	360.1	Land Rights	3,593,142		0		
148	361.0	Structures & Improvements	7,992,932		514,444	(86,904)	
149	362.0	Station Equipment	316,012,790		20,339,310	(3,435,899)	
150	364.0	Poles, Towers, & Fixtures	451,111,922		29,034,603	(4,904,785)	
151	365.0	Overhead Conductor & Devices	452,208,690		29,105,193	(4,916,708)	
152	366.0	Underground Conduit	68,381,398		4,401,184	(743,487)	
153	367.0	Underground Conductor	225,526,232		14,515,387	(2,452,069)	
154	368.0	Line Transformers	397,379,113		25,576,234	(4,320,567)	
155	369.0	Services	93,446,664		6,014,442	(1,016,013)	
156	370.0	Meters	86,735,904		5,582,522	(943,050)	
157	371.0	Installations on Custs. Prem.	44,816,344		2,884,483	(487,273)	
158	373.0	Street Lighting & Signal Sys.	43,041,724		2,770,264	(467,978)	
159		**Total Distribution Plant**	2,198,072,918	0	140,738,066	(23,774,733)	0
160		Reclassed Distribution CWIP In-service at Pro-forma Year End					4,000,189
161		**Adjusted Total Distribution Plant**	2,198,072,918	0	140,738,066	(23,774,733)	4,000,189
		GENERAL PLANT					
162	389.0	Land	18,643,207		0	0	
163	390.0	Structures & Improvements	104,891,737		1,535,993	(2,138,192)	
164	391.0	Office Furniture & Equipment	9,989,968		1,017	(1,416)	
165	391.11	Office Equipment - Computers	69,445				

Support Schedules
(a) F-1.2
(b) WP B 2-4
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(A) WP B 2-4
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Southwestern Electric Power Company
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PRO FORMA YEAR

(1) Line No.	(2) Acct. Number	(3) Acct. Description	(8) Plant Balance End of Pro Forma Year (A)(d) (e)	(9) Pro Forma Year End Accum. Depreciation (f)	(10) Accrual Rates Present	(11) Accrual Rates Proposed	(12) Annual Expense Present (B) (Col. 8 * Col. 10)	(13) Annual Expense Proposed (B) (Col. 8 * Col. 11)
135	354.0	Towers & Fixtures	45,573,481	29,912,448	2.29%	1.73%	1,043,633	788,457
136	355.0	Poles & Fixtures	721,810,667	173,771,262	3.46%	3.32%	24,974,649	23,941,719
137	356.0	OH Conductor & Devices	411,462,360	134,059,833	1.94%	2.16%	7,982,370	8,880,841
138	356.16	OVH Cond-Dev-Smart Grid	12,812,746	-	1.94%	2.16%	248,567	276,545
139	357.0	Underground Conduit	2,307,231	13,879	1.01%	1.99%	23,303	45,974
140	358.0	Underground Conductor & Devices	295	619	1.88%	1.99%	6	6
141	358.16	Ug Cond-Dev-Smart Grid	44,652	-	0	0	839	890
142	359.0	Roads and Trails	131,947	101,742	0	0	1,016	1,845
143		**Total Transmission Plant**	**2,000,888,181**	**557,413,820**			**46,414,360**	**46,512,418**
144		Reclassed Transmission CWIP In-service	16,184,668		2.33%	2.33%	376,332	377,127
145		**Adjusted Total Transmission Plant**	**2,017,072,849**	**557,413,820**			**46,790,692**	**46,889,544**
		DISTRIBUTION PLANT						
146	360.0	Land	7,826,063	0	0.00%	0.00%	0	0
147	360.1	Land Rights	3,593,142	2,541,429	1.24%	1.75%	44,555	62,705
148	361.0	Structures & Improvements	8,420,475	2,534,082	1.20%	1.60%	101,046	134,431
149	362.0	Station Equipment	332,916,205	93,739,494	1.61%	1.95%	5,359,951	6,490,218
150	364.0	Poles, Towers, & Fixtures	475,241,737	206,088,629	2.25%	2.95%	10,692,939	14,009,216
151	365.0	Overhead Conductor & Devices	476,397,175	166,463,051	2.51%	3.11%	11,957,569	14,813,332
152	366.0	Underground Conduit	72,039,095	27,208,523	2.60%	1.69%	1,873,016	1,218,933
153	367.0	Underground Conductor	237,589,548	106,047,376	1.88%	2.57%	4,466,684	6,101,984
154	368.0	Line Transformers	418,634,780	128,161,259	2.02%	2.46%	8,456,423	10,279,921
155	369.0	Services	98,445,094	42,152,312	2.82%	2.95%	2,776,152	2,906,125
156	370.0	Meters	91,375,372	(43,086,710)	4.79%	10.12%	4,376,880	9,247,632
157	371.0	Installations on Custs. Prem.	47,213,554	27,038,822	4.74%	5.37%	2,237,922	2,536,526
158	373.0	Street Lighting & Signal Sys.	45,344,009	27,540,309	2.44%	3.49%	1,106,394	1,580,685
159		**Total Distribution Plant**	**2,315,036,249**	786,428,577			**53,449,531**	**69,381,710**
160		Reclassed Distribution CWIP In-service at	4,000,189					120,292
161		**Adjusted Total Distribution Plant**	2,319,036,438	786,428,577			53,449,531	69,502,002
		GENERAL PLANT						
162	389.0	Land	18,643,206	(207,317)	0.00%	0.00%	0	0
163	390.0	Structures & Improvements	104,289,539	46,053,714	1.76%	1.88%	1,835,496	1,957,528
164	391.0	Office Furniture & Equipment	9,989,968	6,824,362	3.33%	2.76%	332,666	275,326
165	391.11	Office Equipment - Computers	69,045	0	14.29%	12.49%	9,867	8,624

Support Schedules
(a) F-1.2
(b) WP B 2-4
(c) B-2
(d) WP B 2-7
(e) E-17 Part II A
(f) WP B-2-6

Recap Schedules
(A) WP B 2-4
(B) WP C 2-14

Southwestern Electric Power Company
Pro Forma Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

Explanation: This schedule shows actual and proposed rates of depreciation expense, original cost of utility plant in service and accumulated depreciation by account, subtotaled by function, for the pro forma year. Total amounts must reconcile to the recap schedules indicated. If changes to existing depreciation rates are requested, columns 11 and 13 must be completed and the company must provide, as set forth in Section 8 of the Rules of Practice and Procedure, a comprehensive depreciation study which addresses life and salvage estimates in support of such new rates.

PRO FORMA YEAR

(1)	(2)	(3)	(4)	(5)a	(5)b	(6)	(7)
				Pro Forma Adjustments			
Line No.	Acct. Number	Acct. Description	Plant Balance Beginning of Pro Forma Year (a) (A)	Additions (c)	Additions(b)	Retirements (b)	Reclassifications(d)
166	392.0	Transportation Equipment	4,118,518		0	0	
167	393.0	Stores Equipment	3,007,076		44,034	(61,298)	
168	394.0	Tools Shop & Garage Equipment	26,450,904		387,337	(539,195)	
169	395.0	Laboratory Equipment	5,501,275		0	0	
170	396.0	Power Operated Equipment	759,763		0	0	
171	397.0	Communication Equipment	33,200,943		528,399	(735,561)	
172	397.11	Communication Equipment	347,494				
173	397.12	Communication Equipment	2,444,692				
174	397.13	Communication Equipment	559,984				
175	398.0	Miscellaneous Equipment	2,606,866		38,174	(53,140)	
176	399.0	Fuel Related Assets-Lignite	66,070,209		981,212	(1,365,903)	
177	399.10	Fuel Related Assets-Lignite	19,880				
178	399.19	ARO - Office Bldgs.	935,887				
179	399.3	Alliance Rail Facility	22,606,789.00				
180		Total General Plant	302,224,637	0	3,516,166	(4,894,705)	0
181		AFUDC Generation		44,142,485			
182		AFUDC Transmission		870,097			
183		AFUDC Distribution		(3,705,457)			
184		AFUDC Fuel					
185		AFUDC General		2,048,252			
186		Rounding					
187		**Total Plant A/C 101 & 106**	9,198,366,842	43,355,377	416,611,232	(77,849,173)	34,109,098

Support Schedules
(a) F-1.2
(b) WP B 2-4
(c) B-2
(d) WP B 2-7
(e) E-17 Part II A
(f) WP B-2-6

Recap Schedules
(A) WP B 2-4
(B) WP C 2-14

SCHEDULE F-1.3

Southwestern Electric Power Company
Pro Forma Year Depreciation Information
Test Year Ending December 31, 2018
Docket No. 19-008-U

PRO FORMA YEAR

(1)	(2)	(3)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	Acct. Number	Acct. Description	Plant Balance End of Pro Forma Year (A)(d) (e)	Pro Forma Year End Accum. Depreciation (f)	Accrual Rates Present	Accrual Rates Proposed	Annual Expense Present (B) (Col. 8 * Col. 10)	Annual Expense Proposed (B) (Col. 8 * Col. 11)
166	392.0	Transportation Equipment	4,118,518	3,943,076	4.60%	4.32%	189,452	177,861
167	393.0	Stores Equipment	2,989,813	1,831,431	3.40%	3.04%	101,654	90,918
168	394.0	Tools Shop & Garage Equipment	26,299,046	9,608,047	2.86%	2.76%	752,153	726,410
169	395.0	Laboratory Equipment	5,501,275	5,545,881	2.86%	2.38%	157,336	130,779
170	396.0	Power Operated Equipment	759,763	32,774	5.00%	4.70%	37,988	35,735
171	397.0	Communication Equipment	33,010,333	18,796,820	4.75%	4.42%	1,567,991	1,460,377
172	397.11	Communication Equipment	347,494		4.75%	4.42%	16,506	15,373
173	397.12	Communication Equipment	2,430,659		4.75%	4.42%	115,456	107,532
174	397.13	Communication Equipment	557,467		4.75%	4.42%	26,480	24,662
175	398.0	Miscellaneous Equipment	2,591,901	1,371,056	5.00%	4.47%	129,595	115,858
176	399.0	Fuel Related Assets-Lignite	65,690,891	80,145,336			0	0
177	399.10	Fuel Related Assets-Lignite	19,880				0	0
178	399.19	ARO - Office Bldgs.	930,512	0	3.25%	1.71%	30,242	15,912
179	399.3	Alliance Rail Facility	22,606,788					0
180		Total General Plant	300,846,098	173,945,182			5,302,881	5,142,896
181		AFUDC Generation	44,142,485				0	1,501,259
182		AFUDC Transmission	870,097				0	63,482
183		AFUDC Distribution	(3,705,457)				0	441
184		AFUDC Fuel	0				0	0
185		AFUDC General	2,048,252				0	830
186		Rounding	6				0	0
187		**Total Plant A/C 101 & 106**	9,614,593,380	3,175,319,569			207,664,032	268,486,982
				3,175,319,569 (f)				

Support Schedules
(a) F-1.2
(b) WP B 2-4
(c) B-2
(d) WP B 2-7
(e) E-17 Part II A
(f) WP B-2-6

Recap Schedules
(A) WP B 2-4
(B) WP C 2-14

Southwestern Electric Power Company
Proforma Year Depreciation Adjustment
Test Year Ending December 31, 2018
Docket No. 19-008-U

WP F-1.3

Line No.	Description			
1	Depreciation and Amortization of Intangible Assets as Calculated on Schedule F-1.3		(A)	268,486,982
2	Total Company Depreciation and Amortization at proposed rates			268,486,982
3	Less: Pro Forma Year Book Depreciation Expense Schedule C-1		(a)	239,098,916
4	Depreciation Adjustment to Test Year (B)	403 & 404		29,388,066

Purpose: To adjust total company test year depreciation expense to reflect proposed depreciation rates applied to adjusted pro forma year end plant balances as shown on Schedule F 1.3

Support Schedules
(a) Schedule C-1

Recap Schedules
(A) Schedule F-1.3
(B) WP C 2-14

Southwestern Electric Power Company **WP F-1.3.1**
Turk Depreciation Adjustment
Test Year Ending December 31, 2018
Docket No. 19-008-U

	Acct	Increase (Decrease) (a) (A)
To eliminate depreciation expense for the Turk generation plant	403	(34,642,317)

Purpose: Turk power plant is not included in Arkansas rate base, thus asset balance and related depreciation expense are excluded in determining Arkansas retail rates

Support Schedules
(a) Schedule F-1.3

Recap Schedules
(A) WP C 2-14-1

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TST YEAR ENDED DECEMBER 31, 2018

Schedule G-1
Cost of Service Study
Summary

Explanation: Schedule showing the major categories of rate base, revenue, and expense for pro forma year by Total Company, all Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedules or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non-Arkansas) amounts on the supporting schedules. The schedule shall also show the calculation of the rate schedule revenue deficiency and revenue requirement for the above groups at an equal rate of return. If the proposed rate schedule revenue requirement is different from that resulting from the use of equal rates of return, that calculation should also be shown.

Line No	Description	Total Company	Other Jurisdictions	Arkansas Jurisdiction	RESIDENTIAL	COMMERCIAL / SMALL INDUSTRIAL	LARGE INDUSTRIAL	MUNICIPAL	LIGHTING
		1	2	3	4	5	6	7	8
1	**RATE BASE (a)**								
2	Gross Plant in Service	$ 7,927,359,543	$ 6,354,318,652	$ 1,573,040,891	$ 650,806,372	$ 746,528,669	$ 141,566,516	$ 7,749,883	$ 26,389,452
3	Accumulated Depreciation	$ 2,874,920,541	$ 2,307,269,817	$ 567,650,724	$ 232,681,609	$ 270,722,024	$ 53,667,675	$ 2,695,966	$ 7,883,450
4	Total Net Plant	$ 5,052,439,002	$ 4,047,048,836	$ 1,005,390,167	$ 418,124,763	$ 475,806,644	$ 87,898,841	$ 5,053,917	$ 18,506,001
5	Working Capital Assets	$ 888,777,301	$ 713,249,644	$ 175,527,657	$ 72,524,484	$ 82,488,611	$ 16,307,212	$ 896,296	$ 3,311,054
6	Other Rate Base Items	$ 1,086,940	$ 867,586	$ 219,354	$ 79,431	$ 109,996	$ 27,297	$ 1,047	$ 1,583
7	TOTAL RATE BASE (A)	$ 5,942,303,243	$ 4,761,166,065	$ 1,181,137,178	$ 490,728,678	$ 558,405,252	$ 104,233,350	$ 5,951,260	$ 21,818,638
8	**NON-FUEL OPERATING REVENUES**								
9	Present Rate Schedules/Class (c)	$ 966,015,521	$ 836,830,612	$ 129,184,908	$ 53,645,062	$ 59,079,104	$ 11,148,764	$ 753,656	$ 4,558,322
10	Other Operating Revenues	$ 134,349,761	$ 106,601,782	$ 27,747,979	$ 11,448,721	$ 12,688,654	$ 2,980,527	$ 135,328	$ 494,750
11	TOTAL OPERATING REVENUES (A)	$ 1,100,365,282	$ 943,432,394	$ 156,932,888	$ 65,093,783	$ 71,767,758	$ 14,129,291	$ 888,984	$ 5,053,071
12	**EXPENSES (c)**								
13	Operations and Maintenance Expense								
14	Production	$ 159,652,798	$ 130,065,634	$ 29,587,164	$ 10,527,157	$ 14,927,644	$ 3,766,419	$ 143,741	$ 222,202
15	Transmission	$ 146,698,004	$ 116,789,989	$ 29,908,015	$ 11,592,750	$ 14,506,558	$ 3,659,120	$ 143,577	$ 6,010
16	Distribution	$ 86,604,706	$ 71,325,645	$ 15,279,061	$ 7,035,964	$ 6,903,515	$ 512,638	$ 93,422	$ 733,522
17	Customer Accounts	$ 22,326,452	$ 17,242,860	$ 5,083,592	$ 3,848,663	$ 850,459	$ 337,917	$ 28,437	$ 18,115
18	Customer Services and Informational	$ 3,125,672	$ 2,143,041	$ 982,631	$ 477,915	$ 317,964	$ 76,647	$ 5,171	$ 104,933
19	Sales	$ 144,231	$ 112,838	$ 31,393	$ 15,268	$ 10,158	$ 2,449	$ 165	$ 3,352
20	Administrative and General	$ 79,502,811	$ 64,102,806	$ 15,400,005	$ 6,765,525	$ 6,754,670	$ 1,440,874	$ 80,483	$ 358,453
21	ETC (SO2 Allowance - Acct 4118)	$ 619,127	$ 498,755	$ 120,372	$ 48,542	$ 57,947	$ 12,735	$ 508	$ 639
22	TOTAL OPERATION & MAINTENANCE EXPENSE	$ 498,673,801	$ 402,281,569	$ 96,392,232	$ 40,311,785	$ 44,328,917	$ 9,808,800	$ 495,503	$ 1,447,226
23	Depreciation and Amortization Expense	$ 237,290,374	$ 189,837,314	$ 47,453,060	$ 19,903,260	$ 22,278,786	$ 4,150,747	$ 236,161	$ 884,106
24	Taxes Other Than Income Taxes	$ 101,238,420	$ 86,754,092	$ 14,484,328	$ 6,046,625	$ 6,796,718	$ 1,301,971	$ 72,431	$ 266,584
25	Income Taxes	$ 10,451,532	$ 18,542,214	$ (8,090,683)	$ (3,422,035)	$ (4,119,972)	$ (1,022,021)	$ (17,567)	$ 490,913
26	TOTAL EXPENSES (A)	$ 847,654,127	$ 697,415,189	$ 150,238,938	$ 62,839,635	$ 69,284,450	$ 14,239,496	$ 786,529	$ 3,088,828
27	OPERATING INCOME	$ 252,711,155	$ 246,017,205	$ 6,693,949	$ 2,254,148	$ 2,483,308	$ (110,205)	$ 102,455	$ 1,964,243
28	EARNED RETURN ON RATE BASE	4.25%	5.17%	0.57%	0.46%	0.44%	-0.11%	1.72%	9.00%

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TST YEAR ENDED DECEMBER 31, 2018

Explanation: Schedule showing the major categories of rate base, revenue, and expense for pro forma year by Total Company, all Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedules or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non-Arkansas) amounts on the supporting schedules. The schedule shall also show the calculation of the rate schedule revenue deficiency and revenue requirement for the above groups at an equal rate of return. If the proposed rate schedule revenue requirement is different from that resulting from the use of equal rates of return, that calculation should also be shown.

Line No	Description	Total Company 1	Other Jurisdictions 2	Arkansas Jurisdiction 3	RESIDENTIAL 4	COMMERCIAL / SMALL INDUSTRIAL 5	LARGE INDUSTRIAL 6	MUNICIPAL 7	LIGHTING 8
29	COST OF SERVICE REVENUE REQUIREMENT								
30	REQUIRED RETURN ON RATE BASE GIVEN EQUAL RATES OF RETURN	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%
31	REQUIRED OPERATING INCOME (L7*L30)	$ 309,742,557	$ 248,175,781	$ 61,566,775	$ 25,579,232	$ 29,106,874	$ 5,433,163	$ 310,209	$ 1,137,297
32	INCOME DEFICIENCY / (SURPLUS) (L31-L27)	$ 57,031,402	$ 2,158,576	$ 54,872,826	$ 23,325,084	$ 26,623,565	$ 5,543,368	$ 207,754	$ (826,946)
33	REVENUE CONVERSION FACTOR (d) (A)	1.35817	1.35817	1.35817	1.36558	1.35444	1.35394	1.35382	1.35382
34	REVENUE DEFICIENCY / (SURPLUS) (L33*L32)	$ 77,458,574	$ 2,931,722	$ 74,526,851	$ 31,677,180	$ 36,152,781	$ 7,525,343	$ 282,656	$ (1,111,109)
35	RATE SCHEDULE REVENUE REQUIREMENT (L9+L34)	$ 1,043,474,094	$ 839,762,334	$ 203,711,760	$ 85,322,242	$ 95,231,886	$ 18,674,108	$ 1,036,312	$ 3,447,212
36	FUEL REVENUES @ PRESENT RATES (b)	$ 612,134,589	$ 488,061,949	$ 124,072,640	$ 37,536,702	$ 65,773,685	$ 18,830,669	$ 692,259	$ 1,239,325
37	OTHER RIDERS @PRESENT RATES (b)	$ 131,896,129	$ 90,636,200	$ 41,259,929	$ 17,159,503	$ 21,344,186	$ 2,139,549	$ 285,571	$ 331,120
38	% INCREASE ON PRESENT RATE SCHEDULE REVENUE (L34/L9)	8.02%	0.35%	57.69%	59.05%	61.19%	67.50%	37.50%	-24.38%
39	% INCREASE ON PRESENT RATE SCHED REV +FUEL REV (L34/(L9+L36))	4.91%	0.22%	29.43%	34.74%	28.96%	25.10%	19.55%	-19.16%
40	% INCREASE ON PRESENT RATE SCHED REV +FUEL REV + PLUS OTHER RIDERS (L34/(L9+L36+L37))	4.53%	0.21%	25.30%	29.24%	24.73%	23.43%	16.32%	-18.13%
41	TOTAL REVENUE REQUIREMENT (L10+L35+L36+L37)	$ 1,921,854,573	$ 1,525,062,265	$ 396,792,308	$ 151,467,168	$ 195,038,410	$ 42,624,853	$ 2,149,469	$ 5,512,407

Explanation: Schedule showing the major categories of rate base, revenue, and expense for pro forma year by Total Company, all Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedules or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non-Arkansas) amounts on the supporting schedules. The schedule shall also show the calculation of the rate schedule revenue deficiency and revenue requirement for the above groups at an equal rate of return. If the proposed rate schedule revenue requirement is different from that resulting from the use of equal rates of return, that calculation should also be shown.

Line No	Description	Total Company 1	Other Jurisdictions 2	Arkansas Jurisdiction 3	RESIDENTIAL 4	COMMERCIAL / SMALL INDUSTRIAL 5	LARGE INDUSTRIAL 6	MUNICIPAL 7	LIGHTING 8
42	**PROPOSED REVENUE REQUIREMENT**								
43	PROPOSED RETURN ON RATE BASE	5.21%	5.21%	5.21%	5.21%	5.30%	4.76%	5.21%	5.21%
44	REQUIRED OPERATING INCOME (L7*L43)	$ 309,742,557	$ 248,175,781	$ 61,566,797	$ 25,578,715	$ 29,582,083	$ 4,958,503	$ 310,044	$ 1,137,452
45	INCOME DEFICIENCY / (SURPLUS) (L44-L27)	$ 57,031,402	$ 2,158,576	$ 54,872,848	$ 23,324,567	$ 27,098,775	$ 5,068,708	$ 207,589	$ (826,791)
46	REVENUE CONVERSION FACTOR (d) (A)	1.35817	1.35817	1.35817	1.36558	1.35444	1.35394	1.35382	1.35382
47	REVENUE DEFICIENCY / (SURPLUS) (L45*L46)	$ 77,458,574	$ 2,931,722	$ 74,526,881	$ 31,676,480	$ 36,796,130	$ 6,882,738	$ 282,432	$ (1,110,899)
48	RATE SCHEDULE REVENUE REQUIREMENT (L9+L47)	$ 1,043,474,094	$ 839,762,334	$ 203,711,789	$ 85,321,541	$ 95,875,234	$ 18,031,502	$ 1,036,089	$ 3,447,422
49	FUEL REVENUES @ PRESENT RATES (b)	$ 612,134,589	$ 488,061,949	$ 124,072,640	$ 37,536,702	$ 65,773,685	$ 18,830,669	$ 692,259	$ 1,239,325
50	OTHER RIDER @ PRESENT RATES (b)	$ 131,896,129	$ 90,636,200	$ 41,259,929	$ 17,159,503	$ 21,344,186	$ 2,139,549	$ 285,571	$ 331,120
51	% INCREASE ON PRESENT RATE SCHEDULE REVENUE (L47/L9)	8.02%	0.35%	57.69%	59.05%	62.28%	61.74%	37.47%	-24.37%
52	% INCREASE ON PRESENT RATE SCH REV + FUEL REV (L47/(L9+L49))	4.91%	0.22%	29.43%	34.74%	29.47%	22.96%	19.53%	-19.16%
53	% INCREASE ON PRESENT RATE SCH REV + FUEL REV + OTHER RIDERS (L47/(L9+L49+L50))	4.53%	0.21%	25.30%	29.24%	25.17%	21.43%	16.31%	-18.13%
54	TOTAL REVENUE REQUIREMENT (b) (L10+L48+L49+L50)	$ 1,921,854,573	$ 1,525,062,265	$ 396,792,337	$ 151,466,468	$ 195,681,759	$ 41,982,248	$ 2,149,245	$ 5,512,617

Supporting Schedules
(a) G-2
(b) H-1
(c) G-3
(d) C-5

Recap Schedules
(A) A-1

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TST YEAR ENDED DECEMBER 31, 2018

Schedule G-1
Cost of Service Study
Summary

Explanation: Schedule showing the major categories of rate base, revenue, and expense for pro forma year by Total Company, all Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedules or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non-Arkansas) amounts on the supporting schedules. The schedule shall also show the calculation of the rate schedule revenue deficiency and revenue requirement for the above groups at an equal rate of return. If the proposed rate schedule revenue requirement is different from that resulting from the use of equal rates of return, that calculation should also be shown.

		RESIDENTIAL			COMMERCIAL / SMALL INDUSTRIAL					
		BASIC	WITH SPACE HEAT	TOTAL RESIDENTIAL	Light and Power PRI	Light and Power SEC	GENERAL SERVICE	Light and Power TOU SEC	Light and Power TOU PRI	TOTAL
Line No	Description	9	11	12	14	15	17	19	20	21
1	**RATE BASE (a)**									
2	Gross Plant in Service	$ 549,060,190	$ 101,746,183	$ 650,806,372	$ 150,512,245	$ 409,792,553	$ 179,657,723	$ 2,985,855	$ 3,580,294	$ 6,566,148
3	Accumulated Depreciation	$ 197,288,465	$ 35,393,144	$ 232,681,609	$ 55,171,522	$ 148,774,152	$ 64,528,304	$ 958,872	$ 1,289,174	$ 2,248,046
4	Total Net Plant	$ 351,771,725	$ 66,353,039	$ 418,124,763	$ 95,340,723	$ 261,018,401	$ 115,129,419	$ 2,026,983	$ 2,291,119	$ 4,318,102
5	Working Capital Assets	$ 61,058,167	$ 11,466,317	$ 72,524,484	$ 16,927,440	$ 44,829,309	$ 19,917,608	$ 370,052	$ 444,202	$ 814,254
6	Other Rate Base Items	$ 67,277	$ 12,153	$ 79,431	$ 25,451	$ 60,085	$ 23,507	$ 289	$ 666	$ 954
7	TOTAL RATE BASE (A)	$ 412,897,169	$ 77,831,509	$ 490,728,678	$ 112,293,614	$ 305,907,794	$ 135,070,534	$ 2,397,323	$ 2,735,987	$ 5,133,310
8	**NON-FUEL OPERATING REVENUES**									
9	Present Rate Schedules/Class (c)	$ 45,329,688	$ 8,315,373	$ 53,645,062	$ 12,101,967	$ 30,742,086	$ 15,799,494	$ 248,498	$ 187,060	$ 435,558
10	Other Operating Revenues	$ 9,547,583	$ 1,901,139	$ 11,448,721	$ 2,882,653	$ 6,809,150	$ 2,894,189	$ 39,874	$ 62,788	$ 102,662
11	TOTAL OPERATING REVENUES (A)	$ 54,877,271	$ 10,216,512	$ 65,093,783	$ 14,984,619	$ 37,551,236	$ 18,693,683	$ 288,371	$ 249,848	$ 538,220
12	**EXPENSES (c)**									
13	Operations and Maintenance Expense									
14	Production	$ 8,892,246	$ 1,634,911	$ 10,527,157	$ 3,504,285	$ 8,142,780	$ 3,146,955	$ 39,945	$ 93,680	$ 133,625
15	Transmission	$ 9,601,917	$ 1,990,833	$ 11,592,750	$ 3,456,114	$ 7,893,217	$ 3,041,704	$ 41,992	$ 73,531	$ 115,522
16	Distribution	$ 5,884,436	$ 1,151,528	$ 7,035,964	$ 991,063	$ 3,813,249	$ 2,016,481	$ 52,385	$ 30,337	$ 82,722
17	Customer Accounts	$ 3,356,972	$ 491,690	$ 3,848,663	$ 34,400	$ 139,605	$ 606,652	$ 45,471	$ 24,333	$ 69,803
18	Customer Services and Informational	$ 406,299	$ 71,617	$ 477,915	$ 69,593	$ 144,477	$ 100,950	$ 803	$ 2,142	$ 2,945
19	Sales	$ 12,980	$ 2,288	$ 15,268	$ 2,223	$ 4,616	$ 3,225	$ 26	$ 68	$ 94
20	Administrative and General	$ 5,741,597	$ 1,023,928	$ 6,765,525	$ 1,361,935	$ 3,549,581	$ 1,759,470	$ 39,699	$ 43,985	$ 83,683
21	ETC (SO2 Allowance - Acct 4118)	$ 41,758	$ 6,784	$ 48,542	$ 12,072	$ 31,954	$ 13,528	$ 132	$ 262	$ 394
22	TOTAL OPERATION & MAINTENANCE EXPENSE	$ 33,938,206	$ 6,373,580	$ 40,311,785	$ 9,431,685	$ 23,719,478	$ 10,688,966	$ 220,452	$ 268,336	$ 488,789
23	Depreciation and Amortization Expense	$ 16,817,121	$ 3,086,139	$ 19,903,260	$ 4,425,273	$ 12,181,087	$ 5,468,596	$ 95,221	$ 108,608	$ 203,830
24	Taxes Other Than Income Taxes	$ 5,105,252	$ 941,373	$ 6,046,625	$ 1,368,736	$ 3,705,667	$ 1,660,142	$ 28,793	$ 33,380	$ 62,173
25	Income Taxes	$ (2,877,050)	$ (544,985)	$ (3,422,035)	$ (831,081)	$ (2,548,827)	$ (650,718)	$ (29,327)	$ (60,020)	$ (89,347)
26	TOTAL EXPENSES (A)	$ 52,983,528	$ 9,856,106	$ 62,839,635	$ 14,394,613	$ 37,057,406	$ 17,166,986	$ 315,139	$ 350,305	$ 665,444
27	OPERATING INCOME	$ 1,893,743	$ 360,406	$ 2,254,148	$ 590,006	$ 493,831	$ 1,526,696	$ (26,768)	$ (100,457)	$ (127,225)
28	EARNED RETURN ON RATE BASE	0.46%	0.46%	0.46%	0.53%	0.16%	1.13%	-1.12%	-3.67%	-2.48%

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TST YEAR ENDED DECEMBER 31, 2018

Explanation: Schedule showing the major categories of rate base, revenue, and expense for pro forma year by Total Company, all Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedules or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non-Arkansas) amounts on the supporting schedules. The schedule shall also show the calculation of the rate schedule revenue deficiency and revenue requirement for the above groups at an equal rate of return. If the proposed rate schedule revenue requirement is different from that resulting from the use of equal rates of return, that calculation should also be shown.

		RESIDENTIAL			COMMERCIAL / SMALL INDUSTRIAL					
		BASIC	WITH	TOTAL	Light and Power		GENERAL	Light and Power TOU		
Line			SPACE HEAT	RESIDENTIAL	PRI	SEC	SERVICE	SEC	PRI	TOTAL
No	Description	9	11	12	14	15	17	19	20	21
29	COST OF SERVICE REVENUE REQUIREMENT									
30	REQUIRED RETURN ON RATE BASE GIVEN EQUAL RATES OF RETURN	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%
31	REQUIRED OPERATING INCOME (L7*L30)	$ 21,522,265	$ 4,056,967	$ 25,579,232	$ 5,853,305	$ 15,945,444	$ 7,040,552	$ 124,960	$ 142,613	$ 267,574
32	INCOME DEFICIENCY / (SURPLUS) (L31-L27)	$ 19,628,522	$ 3,696,562	$ 23,325,084	$ 5,263,299	$ 15,451,613	$ 5,513,855	$ 151,728	$ 243,070	$ 394,799
33	REVENUE CONVERSION FACTOR (d) (A)	1.36558	1.36558	1.36558	1.35444	1.35444	1.35444	1.35444	1.35444	1.35444
34	REVENUE DEFICIENCY / (SURPLUS) (L33*L32)	$ 26,657,322	$ 5,019,859	$ 31,677,180	$ 7,147,941	$ 20,975,562	$ 7,493,986	$ 205,872	$ 329,420	$ 535,292
35	RATE SCHEDULE REVENUE REQUIREMENT (L9+L34)	$ 71,987,010	$ 13,335,232	$ 85,322,242	$ 19,249,908	$ 51,717,648	$ 23,293,480	$ 454,370	$ 516,480	$ 970,850
36	FUEL REVENUES @ PRESENT RATES (b)	$ 30,832,151	$ 6,704,551	$ 37,536,702	$ 17,158,736	$ 35,521,797	$ 12,361,503	$ 203,189	$ 528,460	$ 731,649
37	OTHER RIDERS @PRESENT RATES (b)	$ 14,094,589	$ 3,064,914	$ 17,159,503	$ 4,328,081	$ 11,696,274	$ 5,054,217	$ 82,222	$ 183,392	$ 265,614
38	% INCREASE ON PRESENT RATE SCHEDULE REVENUE (L34/L9)	58.81%	60.37%	59.05%	59.06%	68.23%	47.43%	82.85%	176.10%	122.90%
39	% INCREASE ON PRESENT RATE SCHED REV +FUEL REV (L34/(L9+L36))	35.00%	33.42%	34.74%	24.43%	31.65%	26.61%	45.58%	46.04%	45.86%
40	% INCREASE ON PRESENT RATE SCHED REV +FUEL REV + PLUS OTHER RIDERS (L34/(L9+L36+L37))	29.54%	27.76%	29.24%	21.28%	26.91%	22.56%	38.56%	36.65%	37.36%
41	TOTAL REVENUE REQUIREMENT (L10+L35+L36+L37)	$ 126,461,333	$ 25,005,836	$ 151,467,168	$ 43,619,377	$ 105,744,869	$ 43,603,390	$ 779,654	$ 1,291,120	$ 2,070,774

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TST YEAR ENDED DECEMBER 31, 2018

Explanation: Schedule showing the major categories of rate base, revenue, and expense for pro forma year by Total Company, all Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedules or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non-Arkansas) amounts on the supporting schedules. The schedule shall also show the calculation of the rate schedule revenue deficiency and revenue requirement for the above groups at an equal rate of return. If the proposed rate schedule revenue requirement is different from that resulting from the use of equal rates of return, that calculation should also be shown.

		RESIDENTIAL			COMMERCIAL / SMALL INDUSTRIAL					
		BASIC	WITH	TOTAL	Light and Power		GENERAL	Light and Power TOU		
Line			SPACE HEAT	RESIDENTIAL	PRI	SEC	SERVICE	SEC	PRI	TOTAL
No	Description	9	11	12	14	15	17	19	20	21
42	**PROPOSED REVENUE REQUIREMENT**									
43	PROPOSED RETURN ON RATE BASE	5.23%	5.11%	0.00%	5.63%	5.21%	5.21%	8.28%	2.53%	0.00%
44	REQUIRED OPERATING INCOME (L7*L43)	$ 21,602,988	$ 3,975,727	$ 25,578,715	$ 6,325,911	$ 15,946,946	$ 7,041,683	$ 198,445	$ 69,099	$ 267,544
45	INCOME DEFICIENCY / (SURPLUS) (L44-L27)	$ 19,709,245	$ 3,615,321	$ 23,324,567	$ 5,735,905	$ 15,453,115	$ 5,514,987	$ 225,212	$ 169,556	$ 394,769
46	REVENUE CONVERSION FACTOR (d) (A)	1.36558	1.36558	1.36558	1.35444	1.35444	1.35444	1.35444	1.35444	1.35444
47	REVENUE DEFICIENCY / (SURPLUS) (L45*L46)	$ 26,766,606	$ 4,909,874	$ 31,676,480	$ 7,787,765	$ 20,977,595	$ 7,495,518	$ 305,357	$ 229,895	$ 535,252
48	RATE SCHEDULE REVENUE REQUIREMENT (L9+L47)	$ 72,096,294	$ 13,225,247	$ 85,321,541	$ 19,889,732	$ 51,719,681	$ 23,295,012	$ 553,854	$ 416,955	$ 970,809
49	FUEL REVENUES @ PRESENT RATES (b)	$ 30,832,151	$ 6,704,551	$ 37,536,702	$ 17,158,736	$ 35,521,797	$ 12,361,503	$ 203,189	$ 528,460	$ 731,649
50	OTHER RIDER @ PRESENT RATES (b)	$ 14,094,589	$ 3,064,914	$ 17,159,503	$ 4,328,081	$ 11,696,274	$ 5,054,217	$ 82,222	$ 183,392	$ 265,614
51	% INCREASE ON PRESENT RATE SCHEDULE REVENUE (L47/L9)	59.05%	59.05%	59.05%	64.35%	68.24%	47.44%	122.88%	122.90%	122.89%
52	% INCREASE ON PRESENT RATE SCH REV + FUEL REV (L47/(L9+L49))	35.14%	32.69%	34.74%	26.62%	31.66%	26.62%	67.60%	32.13%	45.86%
53	% INCREASE ON PRESENT RATE SCH REV + FUEL REV + OTHER RIDERS (L47/(L9+L49+L50))	29.66%	27.15%	29.24%	23.19%	26.91%	22.57%	57.19%	25.57%	37.36%
54	TOTAL REVENUE REQUIREMENT (b) (L10+L48+L49+L50)	$ 126,570,617	$ 24,895,851	$ 151,466,468	$ 44,259,201	$ 105,746,902	$ 43,604,921	$ 879,138	$ 1,191,596	$ 2,070,734

Supporting Schedules
(a) G-2
(b) H-1
(c) G-3
(d) C-5

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TST YEAR ENDED DECEMBER 31, 2018

Explanation: Schedule showing the major categories of rate base, revenue, and expense for pro forma year by Total Company, all Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedules or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non-Arkansas) amounts on the supporting schedules. The schedule shall also show the calculation of the rate schedule revenue deficiency and revenue requirement for the above groups at an equal rate of return. If the proposed rate schedule revenue requirement is different from that resulting from the use of equal rates of return, that calculation should also be shown.

		LARGE INDUSTRIAL					
		Large Power and Light			PULP & PAPER MILL	LP PRIMARY	
Line		PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE	TOTAL
No	Description	22	23	24	25	26	27
1	**RATE BASE (a)**						
2	Gross Plant in Service	$ 55,592,990	$ 28,620,843	$ 84,213,833	$ 46,848,901	$ 10,503,782	$ 57,352,683
3	Accumulated Depreciation	$ 20,520,161	$ 11,158,295	$ 31,678,456	$ 18,436,196	$ 3,553,022	$ 21,989,219
4	Total Net Plant	$ 35,072,829	$ 17,462,547	$ 52,535,376	$ 28,412,705	$ 6,950,759	$ 35,363,464
5	Working Capital Assets	$ 6,166,910	$ 3,387,049	$ 9,553,959	$ 5,497,781	$ 1,255,472	$ 6,753,253
6	Other Rate Base Items	$ 8,928	$ 6,509	$ 15,437	$ 10,544	$ 1,316	$ 11,860
7	TOTAL RATE BASE (A)	$ 41,248,667	$ 20,856,105	$ 62,104,772	$ 33,921,030	$ 8,207,547	$ 42,128,577
8	**NON-FUEL OPERATING REVENUES**						
9	Present Rate Schedules/Class (c)	$ 3,731,299	$ 2,195,911	$ 5,927,210	$ 4,254,656	$ 966,899	$ 5,221,554
10	Other Operating Revenues	$ 988,875	$ 696,879	$ 1,685,754	$ 1,104,528	$ 190,245	$ 1,294,773
11	TOTAL OPERATING REVENUES (A)	$ 4,720,175	$ 2,892,790	$ 7,612,964	$ 5,359,184	$ 1,157,143	$ 6,516,327
12	**EXPENSES (c)**						
13	Operations and Maintenance Expense						
14	Production	$ 1,215,775	$ 907,016	$ 2,122,791	$ 1,461,988	$ 181,641	$ 1,643,629
15	Transmission	$ 1,171,805	$ 877,742	$ 2,049,547	$ 1,388,215	$ 221,359	$ 1,609,573
16	Distribution	$ 389,231	$ 3,137	$ 392,368	$ 3,144	$ 117,126	$ 120,270
17	Customer Accounts	$ 90,101	$ 38,333	$ 128,434	$ 102,022	$ 107,461	$ 209,483
18	Customer Services and Informational	$ 22,177	$ 19,844	$ 42,021	$ 30,951	$ 3,675	$ 34,626
19	Sales	$ 709	$ 634	$ 1,342	$ 989	$ 117	$ 1,106
20	Administrative and General	$ 508,996	$ 305,333	$ 814,328	$ 504,519	$ 122,027	$ 626,545
21	ETC (SO2 Allowance - Acct 4118)	$ 4,595	$ 2,799	$ 7,394	$ 4,729	$ 612	$ 5,341
22	TOTAL OPERATION & MAINTENANCE EXPENSE	$ 3,403,388	$ 2,154,838	$ 5,558,226	$ 3,496,556	$ 754,018	$ 4,250,575
23	Depreciation and Amortization Expense	$ 1,645,876	$ 824,216	$ 2,470,092	$ 1,358,545	$ 322,109	$ 1,680,654
24	Taxes Other Than Income Taxes	$ 503,293	$ 263,814	$ 767,107	$ 435,390	$ 99,474	$ 534,864
25	Income Taxes	$ (489,519)	$ (242,861)	$ (732,380)	$ (231,539)	$ (58,102)	$ (289,642)
26	TOTAL EXPENSES (A)	$ 5,063,038	$ 3,000,007	$ 8,063,045	$ 5,058,952	$ 1,117,499	$ 6,176,451
27	OPERATING INCOME	$ (342,863)	$ (107,218)	$ (450,081)	$ 300,232	$ 39,644	$ 339,876
28	EARNED RETURN ON RATE BASE	-0.83%	-0.51%	-0.72%	0.89%	0.48%	0.81%

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TST YEAR ENDED DECEMBER 31, 2018

Explanation: Schedule showing the major categories of rate base, revenue, and expense for pro forma year by Total Company, all Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedules or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non-Arkansas) amounts on the supporting schedules. The schedule shall also show the calculation of the rate schedule revenue deficiency and revenue requirement for the above groups at an equal rate of return. If the proposed rate schedule revenue requirement is different from that resulting from the use of equal rates of return, that calculation should also be shown.

		LARGE INDUSTRIAL					
		Large Power and Light			PULP & PAPER MILL	LP PRIMARY	
Line No	Description	PRI 22	69 KV 23	TOTAL 24	INDUSTRIAL 25	CURTAILABLE 26	TOTAL 27
29	COST OF SERVICE REVENUE REQUIREMENT						
30	REQUIRED RETURN ON RATE BASE GIVEN EQUAL RATES OF RETURN	5.21%	5.21%	5.21%	5.21%	5.21%	5.21%
31	REQUIRED OPERATING INCOME (L7*L30)	$ 2,150,087	$ 1,087,124	$ 3,237,211	$ 1,768,134	$ 427,818	$ 2,195,952
32	INCOME DEFICIENCY / (SURPLUS) (L31-L27)	$ 2,492,950	$ 1,194,342	$ 3,687,292	$ 1,467,901	$ 388,175	$ 1,856,076
33	REVENUE CONVERSION FACTOR (d) (A)	1.35394	1.35394	1.35394	1.35394	1.35394	1.35394
34	REVENUE DEFICIENCY / (SURPLUS) (L33*L32)	$ 3,381,908	$ 1,620,986	$ 5,002,894	$ 1,995,143	$ 527,307	$ 2,522,450
35	RATE SCHEDULE REVENUE REQUIREMENT (L9+L34)	$ 7,113,207	$ 3,816,896	$ 10,930,104	$ 6,249,798	$ 1,494,206	$ 7,744,004
36	FUEL REVENUES @ PRESENT RATES (b)	$ 5,478,916	$ 4,862,739	$ 10,341,656	$ 7,584,873	$ 904,141	$ 8,489,014
37	OTHER RIDERS @PRESENT RATES (b)	$ 971,446	$ 298,272	$ 1,269,719	$ 559,390	$ 310,440	$ 869,831
38	% INCREASE ON PRESENT RATE SCHEDULE REVENUE (L34/L9)	90.64%	73.82%	84.41%	46.89%	54.54%	48.31%
39	% INCREASE ON PRESENT RATE SCHED REV +FUEL REV (L34/(L9+L36))	36.72%	22.96%	30.75%	16.85%	28.18%	18.40%
40	% INCREASE ON PRESENT RATE SCHED REV +FUEL REV + PLUS OTHER RIDERS (L34/(L9+L36+L37))	33.22%	22.03%	28.53%	16.09%	24.17%	17.30%
41	TOTAL REVENUE REQUIREMENT (L10+L35+L36+L37)	$ 14,552,445	$ 9,674,787	$ 24,227,232	$ 15,498,590	$ 2,899,031	$ 18,397,621

Explanation: Schedule showing the major categories of rate base, revenue, and expense for pro forma year by Total Company, all Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedules or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non-Arkansas) amounts on the supporting schedules. The schedule shall also show the calculation of the rate schedule revenue deficiency and revenue requirement for the above groups at an equal rate of return. If the proposed rate schedule revenue requirement is different from that resulting from the use of equal rates of return, that calculation should also be shown.

		LARGE INDUSTRIAL					
		Large Power and Light			PULP & PAPER MILL	LP PRIMARY	
Line No	Description	PRI 22	69 KV 23	TOTAL 24	INDUSTRIAL 25	CURTAILABLE 26	TOTAL 27
42	**PROPOSED REVENUE REQUIREMENT**						
43	PROPOSED RETURN ON RATE BASE	3.46%	5.21%	0.00%	5.21%	8.26%	0.00%
44	REQUIRED OPERATING INCOME (L7*L43)	$ 1,425,787	$ 1,087,135	$ 2,512,922	$ 1,767,590	$ 677,991	$ 2,445,581
45	INCOME DEFICIENCY / (SURPLUS) (L44-L27)	$ 1,768,650	$ 1,194,353	$ 2,963,003	$ 1,467,358	$ 638,347	$ 2,105,705
46	REVENUE CONVERSION FACTOR (d) (A)	1.35394	1.35394	1.35394	1.35394	1.35394	1.35394
47	REVENUE DEFICIENCY / (SURPLUS) (L45*L46)	$ 2,401,335	$ 1,621,000	$ 4,022,335	$ 1,994,407	$ 865,996	$ 2,860,403
48	RATE SCHEDULE REVENUE REQUIREMENT (L9+L47)	$ 6,132,635	$ 3,816,911	$ 9,949,545	$ 6,249,063	$ 1,832,894	$ 8,081,957
49	FUEL REVENUES @ PRESENT RATES (b)	$ 5,478,916	$ 4,862,739	$ 10,341,656	$ 7,584,873	$ 904,141	$ 8,489,014
50	OTHER RIDER @ PRESENT RATES (b)	$ 971,446	$ 298,272	$ 1,269,719	$ 559,390	$ 310,440	$ 869,831
51	% INCREASE ON PRESENT RATE SCHEDULE REVENUE (L47/L9)	64.36%	73.82%	67.86%	46.88%	89.56%	54.78%
52	% INCREASE ON PRESENT RATE SCH REV + FUEL REV (L47/(L9+L49))	26.07%	22.96%	24.72%	16.85%	46.28%	20.86%
53	% INCREASE ON PRESENT RATE SCH REV + FUEL REV + OTHER RIDERS (L47/(L9+L49+L50))	23.58%	22.03%	22.93%	16.09%	39.70%	19.62%
54	TOTAL REVENUE REQUIREMENT (b) (L10+L48+L49+L50)	$ 13,571,873	$ 9,674,801	$ 23,246,674	$ 15,497,855	$ 3,237,720	$ 18,735,574

Supporting Schedules
(a) G-2
(b) H-1
(c) G-3
(d) C-5

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TST YEAR ENDED DECEMBER 31, 2018

Explanation: Schedule showing the major categories of rate base, revenue, and expense for pro forma year by Total Company, all Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedules or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non-Arkansas) amounts on the supporting schedules. The schedule shall also show the calculation of the rate schedule revenue deficiency and revenue requirement for the above groups at an equal rate of return. If the proposed rate schedule revenue requirement is different from that resulting from the use of equal rates of return, that calculation should also be shown.

Line No	Description	MUNICIPAL PUMPING SERVICE 28	MUNICIPAL SERVICE 29	LIGHTING MUNICIPAL LIGHTING 30	LIGHTING PRIVATE/AREA LIGHTING 32	TOTAL 33
1	**RATE BASE (a)**					
2	Gross Plant in Service	$ 5,444,029	$ 2,305,853	$ 10,801,696	$ 15,587,755	$ 26,389,452
3	Accumulated Depreciation	$ 1,891,149	$ 804,817	$ 3,132,048	$ 4,751,402	$ 7,883,450
4	Total Net Plant	$ 3,552,881	$ 1,501,036	$ 7,669,648	$ 10,836,353	$ 18,506,001
5	Working Capital Assets	$ 622,139	$ 274,157	$ 1,330,630	$ 1,980,423	$ 3,311,054
6	Other Rate Base Items	$ 747	$ 300	$ 481	$ 1,103	$ 1,583
7	TOTAL RATE BASE (A)	$ 4,175,767	$ 1,775,493	$ 9,000,759	$ 12,817,879	$ 21,818,638
8	**NON-FUEL OPERATING REVENUES**					
9	Present Rate Schedules/Class (c)	$ 509,010	$ 244,646	$ 1,388,614	$ 3,169,707	$ 4,558,322
10	Other Operating Revenues	$ 91,952	$ 43,376	$ 224,575	$ 270,174	$ 494,750
11	TOTAL OPERATING REVENUES (A)	$ 600,962	$ 288,022	$ 1,613,190	$ 3,439,882	$ 5,053,071
12	**EXPENSES (c)**					
13	Operations and Maintenance Expense					
14	Production	$ 102,899	$ 40,842	$ 67,432	$ 154,770	$ 222,202
15	Transmission	$ 101,093	$ 42,484	$ 1,798	$ 4,211	$ 6,010
16	Distribution	$ 64,518	$ 28,904	$ 283,202	$ 450,320	$ 733,522
17	Customer Accounts	$ 10,880	$ 17,558	$ 9,556	$ 8,560	$ 18,115
18	Customer Services and Informational	$ 2,872	$ 2,299	$ 47,878	$ 57,055	$ 104,933
19	Sales	$ 92	$ 73	$ 1,530	$ 1,823	$ 3,352
20	Administrative and General	$ 52,353	$ 28,130	$ 136,002	$ 222,451	$ 358,453
21	ETC (SO2 Allowance - Acct 4118)	$ 354	$ 154	$ 194	$ 445	$ 639
22	TOTAL OPERATION & MAINTENANCE EXPENSE	$ 335,059	$ 160,444	$ 547,592	$ 899,634	$ 1,447,226
23	Depreciation and Amortization Expense	$ 164,425	$ 71,737	$ 359,433	$ 524,672	$ 884,106
24	Taxes Other Than Income Taxes	$ 50,306	$ 22,125	$ 105,902	$ 160,682	$ 266,584
25	Income Taxes	$ (14,590)	$ (2,976)	$ 98,757	$ 392,156	$ 490,913
26	TOTAL EXPENSES (A)	$ 535,199	$ 251,329	$ 1,111,683	$ 1,977,145	$ 3,088,828
27	OPERATING INCOME	$ 65,762	$ 36,693	$ 501,506	$ 1,462,737	$ 1,964,243
28	EARNED RETURN ON RATE BASE	1.57%	2.07%	5.57%	11.41%	9.00%

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TST YEAR ENDED DECEMBER 31, 2018

Explanation: Schedule showing the major categories of rate base, revenue, and expense for pro forma year by Total Company, all Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedules or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non-Arkansas) amounts on the supporting schedules. The schedule shall also show the calculation of the rate schedule revenue deficiency and revenue requirement for the above groups at an equal rate of return. If the proposed rate schedule revenue requirement is different from that resulting from the use of equal rates of return, that calculation should also be shown.

		MUNICIPAL		LIGHTING		
Line No	Description	PUMPING SERVICE 28	MUNICIPAL SERVICE 29	MUNICIPAL LIGHTING 30	PRIVATE/AREA LIGHTING 32	TOTAL 33
29	COST OF SERVICE REVENUE REQUIREMENT					
30	REQUIRED RETURN ON RATE BASE GIVEN EQUAL RATES OF RETURN	5.21%	5.21%	5.21%	5.21%	5.21%
31	REQUIRED OPERATING INCOME (L7*L30)	$ 217,662	$ 92,548	$ 469,165	$ 668,132	$ 1,137,297
32	INCOME DEFICIENCY / (SURPLUS) (L31-L27)	$ 151,899	$ 55,855	$ (32,342)	$ (794,605)	$ (826,946)
33	REVENUE CONVERSION FACTOR (d) (A)	1.35382	1.35382	1.35382	1.35382	1.35382
34	REVENUE DEFICIENCY / (SURPLUS) (L33*L32)	$ 206,586	$ 76,070	$ (41,217)	$ (1,069,892)	$ (1,111,109)
35	RATE SCHEDULE REVENUE REQUIREMENT (L9+L34)	$ 715,596	$ 320,716	$ 1,347,397	$ 2,099,815	$ 3,447,212
36	FUEL REVENUES @ PRESENT RATES (b)	$ 507,046	$ 185,213	$ 375,606	$ 863,719	$ 1,239,325
37	OTHER RIDERS @PRESENT RATES (b)	$ 211,293	$ 74,278	$ 100,432	$ 230,688	$ 331,120
38	% INCREASE ON PRESENT RATE SCHEDULE REVENUE (L34/L9)	40.59%	31.09%	-2.97%	-33.75%	-24.38%
39	% INCREASE ON PRESENT RATE SCHED REV +FUEL REV (L34/(L9+L36))	20.33%	17.70%	-2.34%	-26.53%	-19.16%
40	% INCREASE ON PRESENT RATE SCHED REV +FUEL REV + PLUS OTHER RIDERS (L34/(L9+L36+L37))	16.83%	15.09%	-2.21%	-25.09%	-18.13%
41	TOTAL REVENUE REQUIREMENT (L10+L35+L36+L37)	$ 1,525,886	$ 623,583	$ 2,048,010	$ 3,464,397	$ 5,512,407

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TST YEAR ENDED DECEMBER 31, 2018

Explanation: Schedule showing the major categories of rate base, revenue, and expense for pro forma year by Total Company, all Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedules or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non-Arkansas) amounts on the supporting schedules. The schedule shall also show the calculation of the rate schedule revenue deficiency and revenue requirement for the above groups at an equal rate of return. If the proposed rate schedule revenue requirement is different from that resulting from the use of equal rates of return, that calculation should also be shown.

Line No	Description	MUNICIPAL PUMPING SERVICE 28	MUNICIPAL SERVICE 29	LIGHTING MUNICIPAL LIGHTING 30	LIGHTING PRIVATE/AREA LIGHTING 32	TOTAL 33
42	**PROPOSED REVENUE REQUIREMENT**					
43	PROPOSED RETURN ON RATE BASE	4.93%	5.87%	2.77%	6.93%	
44	REQUIRED OPERATING INCOME (L7*L43)	$ 205,795	$ 104,249	$ 249,419	$ 888,033	$ 1,137,452
45	INCOME DEFICIENCY / (SURPLUS) (L44-L27)	$ 140,033	$ 67,556	$ (252,088)	$ (574,704)	$ (826,791)
46	REVENUE CONVERSION FACTOR (d) (A)	1.35382	1.35382	1.35382	1.35382	1.35382
47	REVENUE DEFICIENCY / (SURPLUS) (L45*L46)	$ 190,521	$ 91,912	$ (338,714)	$ (772,185)	$ (1,110,899)
48	RATE SCHEDULE REVENUE REQUIREMENT (L9+L47)	$ 699,531	$ 336,558	$ 1,049,900	$ 2,397,522	$ 3,447,422
49	FUEL REVENUES @ PRESENT RATES (b)	$ 507,046	$ 185,213	$ 375,606	$ 863,719	$ 1,239,325
50	OTHER RIDER @ PRESENT RATES (b)	$ 211,293	$ 74,278	$ 100,432	$ 230,688	$ 331,120
51	% INCREASE ON PRESENT RATE SCHEDULE REVENUE (L47/L9)	37.43%	37.57%	-24.39%	-24.36%	-24.37%
52	% INCREASE ON PRESENT RATE SCH REV + FUEL REV (L47/(L9+L49))	18.75%	21.38%	-19.20%	-19.14%	-19.16%
53	% INCREASE ON PRESENT RATE SCH REV + FUEL REV + OTHER RIDERS (L47/(L9+L49+L50))	15.52%	18.23%	-18.17%	-18.11%	-18.13%
54	TOTAL REVENUE REQUIREMENT (b) (L10+L48+L49+L50)	$ 1,509,821	$ 639,424	$ 1,750,513	$ 3,762,104	$ 5,512,617

Supporting Schedules
(a) G-2
(b) H-1
(c) G-3
(d) C-5

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

JURISDICTIONAL

	FERC ACCT	ELECTRIC PLANT IN SERVICE	TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)	ALLOC
1		PROD - INTANGIBLE PLANT	64,465,055	12,021,586	52,443,469	LABPROD
2		TRAN - INTANGIBLE PLANT	26,539,498	5,410,733	21,128,765	LABTRAN
3		DIST - INTANGIBLE PLANT	66,542,443	13,354,109	53,188,334	LABDIST
4		TOTAL INTANGIBLE PLANT	157,546,996	30,786,428	126,760,568	
5						
6		PRODUCTION PLANT				
7		UNADJUSTED PRODUCTION PLANT	3,089,501,782	600,667,049	2,488,834,733	DEMPROD
8		CONTRA ADJ TO EPIS - PROD	0	0	0	DEMPROD
9		NON-AFUDC ADJUSTED VALUE	3,089,501,782	600,667,049	2,488,834,733	
10		AFUDC ADJ TO EPIS-PROD	44,142,485	8,582,269	35,560,216	DEMPROD
11		TOTAL PRODUCTION PLANT	3,133,644,267	609,249,318	2,524,394,949	
12						
13		TRANSMISSION PLANT				
14	350	350-LAND & LAND RIGHTS	108,837,721	22,189,260	86,648,461	DEMTRANS
15	352	352-STRUCTURES & IMPROVEMENTS	16,543,224	3,372,745	13,170,479	DEMTRANS
16	352	352-STRUCTURES & IMPROVEMENTS GEN	0	0	0	DEMPROD
17	353	353-STATION EQUIPMENT	687,889,404	140,243,262	547,646,142	DEMTRANS
18	353	353-STATION EQUIPMENT GEN	0	0	0	DEMPROD
19	354	354-TOWERS & FIXTURES	45,942,114	9,366,436	36,575,678	DEMTRANS
20	355	355-POLES & FIXTURES	727,649,209	148,349,281	579,299,928	DEMTRANS
21	356	356-OVERHEAD CONDUCTORS & DEVICES	427,706,956	87,198,637	340,508,318	DEMTRANS
22	357	357-UNDERGROUND CONDUIT	2,325,898	474,192	1,851,706	DEMTRANS
23	358	358-UNDERGROUND COND & DEVICES	45,310	9,237	36,072	DEMTRANS
24	359	359- ROADS AND TRAILS	133,014	27,118	105,896	DEMTRANS
25		UNADJUSTED TRANSMISSION PLANT	2,017,072,850	411,230,169	1,605,842,681	
26		CONTRA ADJ TO EPIS-TRANS	0	0	0	DEMTRANS

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JURISDICTIONAL

			TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)	ALLOC
27		NON-AFUDC ADJUSTED VALUE	2,017,072,850	411,230,169	1,605,842,681	
28		AFUDC ADJ TO EPIS - TRANS	870,097	177,391	692,706	DEMTRANS
29		TOTAL TRANSMISSION PLANT	2,017,942,947	411,407,560	1,606,535,386	
1		DISTRIBUTION PLANT				
2	360	360-LAND & LAND RIGHTS	11,438,936	2,769,600	8,669,336	DEM360DA
3	361	361-STRUCTURES & IMPROVEMENTS	8,435,022	2,518,993	5,916,029	DEM361DA
4	362	362-STATION EQUIPMENT	333,491,452	80,952,717	252,538,736	DEM362DA
5	364	364-POLES TOWERS & FIXTURES	0	0	0	
6		PRIMARY	306,964,278	50,994,142	255,970,136	DEM364DAP
7		SECONDARY	169,098,640	36,459,368	132,639,271	DEM364DAS
8		TOTAL ACCOUNT 364	476,062,918	87,453,510	388,609,408	
9	365	365-OVERHEAD CONDUCTORS & DEVICES	0	0	0	
10		PRIMARY	384,103,654	72,922,332	311,181,322	DEM365DAP
11		SECONDARY	93,116,695	24,684,858	68,431,837	DEM365DAS
12		TOTAL ACCOUNT 365	477,220,349	97,607,190	379,613,159	
13	366	366-UNDERGROUND CONDUIT	0	0	0	
14		PRIMARY	32,783,336	7,799,663	24,983,673	DEM366DAP
15		SECONDARY	39,380,237	8,725,046	30,655,190	DEM366DAS
16		TOTAL ACCOUNT 366	72,163,573	16,524,709	55,638,863	
17	367	367-UNDERGROUND CONDUCTORS & DEV.	0			
18		PRIMARY	108,262,829	27,174,239	81,088,590	DEM367DAP
19		SECONDARY	129,737,256	30,398,301	99,338,955	DEM367DAS
20		TOTAL ACCOUNT 367	238,000,085	57,572,539	180,427,545	
21	368	368-LINE TRANSFORMERS	419,358,146	59,647,952	359,710,194	DEM368DA
22	369	369-SERVICES	98,615,198	21,777,859	76,837,339	CUST369
23	370	370-METERS	91,533,265	18,544,958	72,988,307	CUST370
24	371	371-INSTALLATIONS	47,295,135	8,327,075	38,968,060	CUST371L
25	373	373-STREET LIGHTS	45,422,361	7,510,701	37,911,660	CUST373

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JURISDICTIONAL

			TOTAL COMPANY	AT ISSUE ARKANSAS RETAIL	ALL OTHER	ALLOC
			(1)	(2)	(3)	
26	UNADJUSTED DISTRIBUTION PLANT		2,319,036,440	461,207,803	1,857,828,637	
27	CONTRA ADJ TO EPIS- DIST		0	0	0	DISTPLTX
28	NON-AFUDC ADJUSTED VALUE		2,319,036,440	461,207,803	1,857,828,637	
29	AFUDC ADJ TO EPIS - DIST		(3,705,457)	(736,938)	(2,968,519)	DISTPLT
30	TOTAL DISTRIBUTION PLANT		2,315,330,983	460,470,865	1,854,860,118	
	SCHEDULE G-2 ALLOCATION OF RATE BASE					
	ELECTRIC PLANT IN SERVICE					
1	GENERAL PLANT					
2	GENERAL PLANT		302,894,350	61,126,719	241,767,630	LABORT
3	AVAILABLE		0	0	0	AVAIL
4	AVAILABLE		0	0	0	AVAIL
5	AVAILABLE		0	0	0	AVAIL
6	AVAILABLE		0	0	0	AVAIL
7	AVAILABLE		0	0	0	AVAIL
8	AVAILABLE		0	0	0	AVAIL
9	UNADJUSTED GENERAL PLANT		302,894,350	61,126,719	241,767,630	
10	CONTRA ADJ TO EPIS- GENERAL PLT		0	0	0	GENPLT
11	NON-AFUDC ADJUSTED VALUE		302,894,350	61,126,719	241,767,630	
12	AFUDC ADJ TO EPIS - GENERAL - FUEL RELATED		0	0	0	ENERGY
13	AFUDC ADJ TO EPIS - GENERAL - NON FUEL		0	0	0	GENPLT
14	TOTAL GENERAL PLANT		302,894,350	61,126,719	241,767,630	
15				0	0	
16	TOTAL ELEC PLANT IN SERVICE	(a)	7,927,359,543	1,573,040,891	6,354,318,652	
	ELECTRIC PLANT IN SERVICE					
1	LESS: RESERVE FOR DEPRECIATION					
2	PRODUCTION PLANT		1,549,031,415	301,165,753	1,247,865,663	PRODPLT

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Schedule: G-2
Coste of Service Study - Rate Base Detail
Jurisdiction

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

JURISDICTIONAL

		TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)	ALLOC
3	CONTRA ADJ TO DEPR - PROD	0	0	0	PRODPLT
4	NON-AFUDC ADJUSTED VALUE	1,549,031,415	301,165,753	1,247,865,663	
5	AFUDC ADJ TO DEPR - PROD	0	0	0	PRODPLT
6	TOTAL PROD ACCUM DEPR	1,549,031,415	301,165,753	1,247,865,663	
7	TRANSMISSION PLANT	506,250,922	103,211,767	403,039,156	TRANPLT
8	CONTRA ADJ TO DEPR - TRAN	0	0	0	TRANPLT
9	NON-AFUDC ADJUSTED VALUE	506,250,922	103,211,767	403,039,156	
10	AFUDC ADJ TO DEPR - TRAN	0	0	0	TRANPLT
11	TOTAL TRAN ACCUM DEPR	506,250,922	103,211,767	403,039,156	
12	DISTRIBUTION PLANT	608,764,113	121,070,439	487,693,674	DISTPLT
13	CONTRA ADJ TO DEPR - DIST	0	0	0	DISTPLT
14	NON-AFUDC ADJUSTED VALUE	608,764,113	121,070,439	487,693,674	
15	AFUDC ADJ TO DEPR - DIST	0	0	0	DISTPLT
16	TOTAL DIST ACCUM DEPR	608,764,113	121,070,439	487,693,674	
17	GENERAL PLANT				
18	GENERAL	155,625,119	31,406,505	124,218,614	GENPLT
19	GENERAL FUEL	0	0	0	ENERGY
20	TRANSPORTATION	0	0	0	LABORT
21	RWIP GENERATION	0	0	0	PRODPLT
22	RWIP TRANSMISSION	0	0	0	TRANPLT
23	RWIP DISTRIBUTION	0	0	0	DISTPLT
24	INTANGIBLE	55,248,972	10,796,261	44,452,711	INTPLT
25	TOTAL GENERAL PLANT	210,874,090	42,202,766	168,671,324	
26	CONTRA ADJ TO DEPR - GENL	0	0	0	GENPLT
27	NON-AFUDC ADJUSTED VALUE	210,874,090	42,202,766	168,671,324	
28	AFUDC ADJ TO DEPR - GENL	0	0	0	GENPLT
29	TOTAL GENL ACCUM DEPR	210,874,090	42,202,766	168,671,324	
30	TOT ACCUM PROV FOR DEPR	2,874,920,541	567,650,724	2,307,269,817	
31	NET ELECTRIC PLANT IN SERVICE	5,052,439,002	1,005,390,167	4,047,048,836	

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JURISDICTIONAL

		TOTAL COMPANY	AT ISSUE ARKANSAS RETAIL	ALL OTHER	ALLOC
		(1)	(2)	(3)	
	ADDITIONS TO RATE BASE				
1	PLANT HELD FOR FUTURE USE				
2	PRODUCTION	0	0	0	PRODPLT
3	TRANSMISSION	0	0	0	TRANPLT
4	DISTRIBUTION	0	0	0	DISTPLT
5	GENERAL	1,086,940	219,354	867,586	GENPLT
6	LIGNITE	0	0	0	ENERGY
7	TOTAL PLANT HELD FOR FUTURE USE	1,086,940	219,354	867,586	
8	CONSTRUCTION WORK IN PROGRESS				
9	PRODUCTION	0	0	0	PRODPLT
10	TRANSMISSION	0	0	0	TRANPLT
11	DISTRIBUTION	0	0	0	DISTPLTX
12	GENERAL				
13	FUEL	0	0	0	ENERGY
14	OTHER	0	0	0	GENPLT
15	TOTAL GENERAL	0	0	0	
16	TOTAL CONSTRUCTION WORK IN PROGRESS	0	0	0	
17	WORKING CAPITAL				
18	MATERIALS & SUPPLIES				
19	PRODUCTION	27,677,761	5,381,165	22,296,596	PRODPLT
20	TRANSMISSION	17,823,383	3,633,737	14,189,646	TRANPLT
21	DISTRIBUTION	20,450,049	4,067,087	16,382,962	DISTPLT
22	TOT PLANT MAT & SUPP	65,951,193	13,081,989	52,869,204	
23	PREPAYMENTS				
24	FAS 87 PENSION	140,486,900	28,351,481	112,135,419	LABORT
25	INSURANCE/MISC/AR FAC	0	0	0	RBX
26	FUEL RELATED	0	0	0	ENERGY
27	PLANT	0	0	0	PLANT

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JURISDICTIONAL

		TOTAL COMPANY	AT ISSUE ARKANSAS RETAIL	ALL OTHER	ALLOC
		(1)	(2)	(3)	
28	TOTAL PREPAYMENTS	140,486,900	28,351,481	112,135,419	
29	FUEL INVENTORY	67,479,330	11,879,984	55,599,347	ENERGY
30	MISCELLANEOUS WORKING CAP	614,859,878	122,214,204	492,645,674	RBX
31	TOTAL WORKING CAPITAL	888,777,301	175,527,657	713,249,644	
32	PLANT ACQ ADJ NET	0	0	0	DISTPLTLA
33	OTHER ADDITIONS TO RATE BASE				
34	AVAILABLE	0	0	0	AVAIL
35	AVAILABLE	0	0	0	AVAIL
36	AVAILABLE	0	0	0	AVAIL
37	AVAILABLE	0	0	0	AVAIL
38	AVAILABLE	0	0	0	AVAIL
39	AVAILABLE	0	0	0	AVAIL
40	AVAILABLE	0	0	0	AVAIL
41	AVAILABLE	0	0	0	AVAIL
42	AVAILABLE	0	0	0	AVAIL
43	TOTAL OTHER ADDITIONS TO RATE BASE	0	0	0	
44	TOTAL ADDITIONS-RATE-BASE	889,864,240	175,747,011	714,117,229	
	DEDUCTIONS FROM RATE BASE				
1	ACCUM DEFERRED INCOME TAX				
2	PRODUCTION	0	0	0	PRODPLT
3	CONTRA ADJ TO ADIT PROD	0	0	0	PRODPLT
4	NON AFUDC ADJ BASIS	0	0	0	
5	AFUDC ADJ TO ADIT - PROD	0	0	0	PRODPLT
6	TOTAL PROD ADIT	0	0	0	
7					
8	TRANSMISSION	0	0	0	TRANPLT

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Schedule: G-2
Coste of Service Study - Rate Base Detail
Jurisdiction

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

JURISDICTIONAL

		TOTAL COMPANY	AT ISSUE ARKANSAS RETAIL	ALL OTHER	ALLOC
		(1)	(2)	(3)	
9	CONTRA ADJ TO ADIT TRAN	0	0	0	TRANPLT
10	NON AFUDC ADJ BASIS	0	0	0	
11	AFUDC ADJ TO ADIT - TRAN	0	0	0	TRANPLT
12	TOTAL TRAN ADIT	0	0	0	
13					
14	DISTRIBUTION	0	0	0	DISTPLT
15	CONTRA ADJ TO ADIT DIST	0	0	0	DISTPLT
16	NON AFUDC ADJ BASIS	0	0	0	
17	AFUDC ADJ TO ADIT - DIST	0	0	0	DISTPLT
18	TOTAL DIST ADIT	0	0	0	
19					
20	GENERAL	0	0	0	GENPLT
21	CONTRA ADJ TO ADIT GEN	0	0	0	GENPLT
22	NON AFUDC ADJ BASIS	0	0	0	
23	AFUDC ADJ TO ADIT - GEN	0	0	0	GENPLT
24	TOTAL GEN ADIT	0	0	0	
	DEDUCTIONS FROM RATE BASE				
1	PLANT RELATED	0	0	0	PLANT
2	PLANT RELATED	0	0	0	PLANT
3	PLANT RELATED	0	0	0	PLANT
4	PLANT RELATED	0	0	0	PLANT
5	PLANT RELATED	0	0	0	PLANT
6	PLANT RELATED	0	0	0	PLANT
7	PLANT RELATED	0	0	0	PLANT
8	PLANT RELATED	0	0	0	PLANT

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

JURISDICTIONAL

		TOTAL COMPANY	AT ISSUE ARKANSAS RETAIL	ALL OTHER	ALLOC
		(1)	(2)	(3)	
9	PLANT RELATED	0	0	0	PLANT
10		0	0	0	PLANT
11	TOTAL ACCUM DEF INC TAX	0	0	0	
12					
13	CUSTOMER DEPOSITS	0	0	0	CUSTDEPA
14					
15	PRE-1971 ITC	0	0	0	NETPLT
16					
17	OTHER DEDUCTIONS				
18	MISC DEPOSITS	0	0	0	TRANPLT
19	BREMCO LIABILITY	0	0	0	DISTPLTLA
20	POLE ATTACH & MISC PROCEEDS	0	0	0	DISTPLT
21	TOTAL OTHER DEDUCTIONS	0	0	0	
22					
23	TOTAL DEDUCTIONS-RATE BASE	0	0	0	
24					
25	TOTAL RATE BASE	5,942,303,243	1,181,137,178	4,761,166,065	

Supporting Schedules
(a) B-1
(b) G-4
(c) F-1.3
WP's G-2
WP's G-2 and G-3
G Juris WP

Recap Schedules
(A) G-1

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	FERC ACCT	SCHEDULE G-2 ALLOCATION OF RATE BASE ELECTRIC PLANT IN SERVICE	TOTAL AR RETAIL JURISDICTION (1)	RESIDENTIAL (2)	COMMERCIAL / SMALL INDUSTRIAL (3)	LARGE INDUSTRIAL (4)	MUNICIPAL (5)	LIGHTING (6)	ALLOC
1		PROD - INTANGIBLE PLANT	12,021,586	4,353,151	6,028,304	1,495,982	57,382	86,767	LABPROD
2		TRAN - INTANGIBLE PLANT	5,410,733	2,097,273	2,624,417	661,981	25,975	1,087	LABTRAN
3		DIST - INTANGIBLE PLANT	13,354,109	5,906,319	6,020,628	449,698	77,715	899,749	LABDIST
4		TOTAL INTANGIBLE PLANT	30,786,428	12,356,744	14,673,349	2,607,660	161,071	987,604	
5									
6		PRODUCTION PLANT							
7		UNADJUSTED PRODUCTION PLANT	600,667,049	242,229,315	289,162,942	63,551,047	2,534,209	3,189,536	DEMPROD
8		CONTRA ADJ TO EPIS - PROD	-	-	-	-	-	-	DEMPROD
9		NON-AFUDC ADJUSTED VALUE	600,667,049	242,229,315	289,162,942	63,551,047	2,534,209	3,189,536	
10		AFUDC ADJ TO EPIS-PROD	8,582,269	3,460,948	4,131,531	908,011	36,209	45,572	DEMPROD
11		TOTAL PRODUCTION PLANT	609,249,318	245,690,263	293,294,472	64,459,058	2,570,418	3,235,107	
12									
13		TRANSMISSION PLANT							
14	350	350-LAND & LAND RIGHTS	22,189,260	8,600,857	10,762,660	2,714,763	106,522	4,459	DEMTRANS
15	352	352-STRUCTURES & IMPROVEMENTS	3,372,745	1,307,322	1,635,913	412,641	16,191	678	DEMTRANS
16	352	352-STRUCTURES & IMPROVEMENTS GEN	-	-	-	-	-	-	DEMPROD
17	353	353-STATION EQUIPMENT	140,243,262	54,360,180	68,023,470	17,158,176	673,255	28,180	DEMTRANS
18	353	353-STATION EQUIPMENT GEN	-	-	-	-	-	-	DEMPROD
19	354	354-TOWERS & FIXTURES	9,366,436	3,630,557	4,543,088	1,145,944	44,965	1,882	DEMTRANS
20	355	355-POLES & FIXTURES	148,349,281	57,502,183	71,955,207	18,149,914	712,169	29,809	DEMTRANS
21	356	356-OVERHEAD CONDUCTORS & DEVICES	87,198,637	33,799,368	42,294,752	10,668,388	418,608	17,521	DEMTRANS
22	357	357-UNDERGROUND CONDUIT	474,192	183,803	230,002	58,015	2,276	95	DEMTRANS
23	358	358-UNDERGROUND COND & DEVICES	9,237	3,581	4,481	1,130	44	2	DEMTRANS
24	359	359- ROADS AND TRAILS	27,118	10,511	13,153	3,318	130	5	DEMTRANS
25		UNADJUSTED TRANSMISSION PLANT	411,230,169	159,398,361	199,462,725	50,312,290	1,974,162	82,631	
26		CONTRA ADJ TO EPIS-TRANS	-	-	-	-	-	-	DEMTRANS
27		NON-AFUDC ADJUSTED VALUE	411,230,169	159,398,361	199,462,725	50,312,290	1,974,162	82,631	
28		AFUDC ADJ TO EPIS - TRANS	177,391	68,759	86,041	21,703	852	36	DEMTRANS
29		TOTAL TRANSMISSION PLANT	411,407,560	159,467,120	199,548,767	50,333,993	1,975,014	82,666	
1		DISTRIBUTION PLANT							
2	360	360-LAND & LAND RIGHTS	2,769,600	1,184,738	1,381,808	149,264	15,664	38,127	DEM360DA
3	361	361-STRUCTURES & IMPROVEMENTS	2,518,993	1,077,537	1,256,775	135,757	14,247	34,677	DEM361DA

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

			TOTAL AR RETAIL JURISDICTION	RESIDENTIAL	COMMERCIAL / SMALL INDUSTRIAL	LARGE INDUSTRIAL	MUNICIPAL	LIGHTING	ALLOC
			(1)	(2)	(3)	(4)	(5)	(6)	
4	362	362-STATION EQUIPMENT	80,952,717	34,628,734	40,388,896	4,362,827	457,847	1,114,413	DEM362DA
5	364	364-POLES TOWERS & FIXTURES							
6		PRIMARY	50,994,142	21,813,506	25,441,976	2,748,254	288,409	701,997	DEM364DAP
7		SECONDARY	36,459,368	18,576,452	17,039,484	-	245,610	597,823	DEM364DAS
8		TOTAL ACCOUNT 364							
9	365	365-OVERHEAD CONDUCTORS & DEVICES							
10		PRIMARY	72,922,332	31,193,617	36,382,379	3,930,041	412,429	1,003,865	DEM365DAP
11		SECONDARY	24,684,858	12,577,209	11,536,603	-	166,291	404,756	DEM365DAS
12		TOTAL ACCOUNT 365	97,607,190	43,770,826	47,918,982	3,930,041	578,720	1,408,621	
13	366	366-UNDERGROUND CONDUIT							
14		PRIMARY	7,799,663	3,336,422	3,891,404	420,351	44,113	107,372	DEM366DAP
15		SECONDARY	8,725,046	4,445,508	4,077,698	-	58,777	143,064	DEM366DAS
16		TOTAL ACCOUNT 366	16,524,709	7,781,930	7,969,102	420,351	102,890	250,436	
17	367	367-UNDERGROUND CONDUCTORS & DEV.							
18		PRIMARY	27,174,239	11,624,187	13,557,760	1,464,515	153,690	374,087	DEM367DAP
19		SECONDARY	30,398,301	15,488,271	14,206,811	-	204,780	498,440	DEM367DAS
20		TOTAL ACCOUNT 367	57,572,539	27,112,457	27,764,571	1,464,515	358,470	872,526	
21	368	368-LINE TRANSFORMERS	59,647,952	25,515,303	29,759,531	3,214,638	337,353	821,127	DEM368DA
22	369	369-SERVICES	21,777,859	17,739,666	3,862,376	3,670	172,147	-	CUST369
23	370	370-METERS	18,544,958	12,294,363	5,909,640	156,301	184,654	-	CUST370
24	371	371-INSTALLATIONS	8,327,075	-	-	-	-	8,327,075	CUST371L
25	373	373-STREET LIGHTS	7,510,701	-	-	-	-	7,510,701	CUST373
26		UNADJUSTED DISTRIBUTION PLANT	461,207,803	211,495,512	208,693,141	16,585,618	2,756,011	21,677,522	
27		CONTRA ADJ TO EPIS- DIST	-	-	-	-	-	-	DISTPLTX
28		NON-AFUDC ADJUSTED VALUE	461,207,803	211,495,512	208,693,141	16,585,618	2,756,011	21,677,522	
29		AFUDC ADJ TO EPIS - DIST	(736,938)	(337,937)	(333,459)	(26,501)	(4,404)	(34,637)	DISTPLT
30		TOTAL DISTRIBUTION PLANT	460,470,865	211,157,575	208,359,682	16,559,117	2,751,607	21,642,885	
		SCHEDULE G-2 ALLOCATION OF RATE BASE							
		ELECTRIC PLANT IN SERVICE							
1		GENERAL PLANT							
2		GENERAL PLANT	61,126,719	22,134,671	30,652,399	7,606,687	291,773	441,189	LABPROD
3		ENERGY	-	-	-	-	-	-	ENERGY
4		TRANSMISSION	-	-	-	-	-	-	LABTRAN
5		DISTRIBUTION	-	-	-	-	-	-	LABDIST
6		CAPITAL LEASE ASSETS Net	-	-	-	-	-	-	LABORT

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TOTAL AR RETAIL JURISDICTION (1)	RESIDENTIAL (2)	COMMERCIAL / SMALL INDUSTRIAL (3)	LARGE INDUSTRIAL (4)	MUNICIPAL (5)	LIGHTING (6)	ALLOC
7	OTHER	-	-	-	-	-	-	LABORT
8	OTHER	-	-	-	-	-	-	LABORT
9	UNADJUSTED GENERAL PLANT	61,126,719	22,134,671	30,652,399	7,606,687	291,773	441,189	
10	CONTRA ADJ TO EPIS- GENERAL PLT	-	-	-	-	-	-	GENPLT
11	NON-AFUDC ADJUSTED VALUE	61,126,719	22,134,671	30,652,399	7,606,687	291,773	441,189	
12	AFUDC ADJ TO EPIS - GENERAL - FUEL RELAT	-	-	-	-	-	-	ENERGY
13	AFUDC ADJ TO EPIS - GENERAL - NON FUEL	-	-	-	-	-	-	GENPLT
14	TOTAL GENERAL PLANT	61,126,719	22,134,671	30,652,399	7,606,687	291,773	441,189	
15								
16	TOTAL ELEC PLANT IN SERVICE	1,573,040,891	650,806,372	746,528,669	141,566,516	7,749,883	26,389,452	
	SCHEDULE G-2 ALLOCATION OF RATE BASE							
	ELECTRIC PLANT IN SERVICE							
1	LESS: RESERVE FOR DEPRECIATION							
2	PRODUCTION PLANT	301,165,753	121,450,268	144,982,108	31,863,574	1,270,616	1,599,187	PRODPLT
3	CONTRA ADJ TO DEPR - PROD	-	-	-	-	-	-	PRODPLT
4	NON-AFUDC ADJUSTED VALUE	301,165,753	121,450,268	144,982,108	31,863,574	1,270,616	1,599,187	
5	AFUDC ADJ TO DEPR - PROD	-	-	-	-	-	-	PRODPLT
6	TOTAL PROD ACCUM DEPR	301,165,753	121,450,268	144,982,108	31,863,574	1,270,616	1,599,187	
7	TRANSMISSION PLANT	103,211,767	40,006,273	50,061,746	12,627,528	495,481	20,739	TRANPLT
8	CONTRA ADJ TO DEPR - TRAN	-	-	-	-	-	-	TRANPLT
9	NON-AFUDC ADJUSTED VALUE	103,211,767	40,006,273	50,061,746	12,627,528	495,481	20,739	
10	AFUDC ADJ TO DEPR - TRAN	-	-	-	-	-	-	TRANPLT
11	TOTAL TRAN ACCUM DEPR	103,211,767	40,006,273	50,061,746	12,627,528	495,481	20,739	
12	DISTRIBUTION PLANT	121,070,439	55,519,126	54,783,484	4,353,847	723,473	5,690,509	DISTPLT
13	CONTRA ADJ TO DEPR - DIST	-	-	-	-	-	-	DISTPLT
14	NON-AFUDC ADJUSTED VALUE	121,070,439	55,519,126	54,783,484	4,353,847	723,473	5,690,509	
15	AFUDC ADJ TO DEPR - DIST	-	-	-	-	-	-	DISTPLT
16	TOTAL DIST ACCUM DEPR	121,070,439	55,519,126	54,783,484	4,353,847	723,473	5,690,509	
17	GENERAL PLANT							
18	GENERAL	31,406,505	11,372,648	15,749,000	3,908,266	149,911	226,680	GENPLT
19	GENERAL FUEL	-	-	-	-	-	-	ENERGY
20	TRANSPORTATION	-	-	-	-	-	-	LABORT
21	RWIP GENERATION	-	-	-	-	-	-	PRODPLT
22	RWIP TRANSMISSION	-	-	-	-	-	-	TRANPLT
23	RWIP DISTRIBUTION	-	-	-	-	-	-	DISTPLT

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TOTAL AR RETAIL JURISDICTION	RESIDENTIAL	COMMERCIAL / SMALL INDUSTRIAL	LARGE INDUSTRIAL	MUNICIPAL	LIGHTING	ALLOC
		(1)	(2)	(3)	(4)	(5)	(6)	
24	INTANGIBLE	10,796,261	4,333,293	5,145,687	914,461	56,485	346,335	INTPLT
25	TOTAL GENERAL PLANT	42,202,766	15,705,942	20,894,687	4,822,726	206,396	573,015	
26	CONTRA ADJ TO DEPR - GENL	-	-	-	-	-	-	GENPLT
27	NON-AFUDC ADJUSTED VALUE	42,202,766	15,705,942	20,894,687	4,822,726	206,396	573,015	
28	AFUDC ADJ TO DEPR - GENL	-	-	-	-	-	-	GENPLT
29	TOTAL GENL ACCUM DEPR	42,202,766	15,705,942	20,894,687	4,822,726	206,396	573,015	
30	TOT ACCUM PROV FOR DEPR	567,650,724	232,681,609	270,722,024	53,667,675	2,695,966	7,883,450	
31	NET ELECTRIC PLANT IN SERVICE	1,005,390,167	418,124,763	475,806,644	87,898,841	5,053,917	18,506,001	
WORKPAPER E								
	ADDITIONS TO RATE BASE							
1	PLANT HELD FOR FUTURE USE							
2	PRODUCTION	-	-	-	-	-	-	PRODPLT
3	TRANSMISSION	-	-	-	-	-	-	TRANPLT
4	DISTRIBUTION	-	-	-	-	-	-	DISTPLT
5	GENERAL	219,354	79,431	109,996	27,297	1,047	1,583	GENPLT
6	LIGNITE	-	-	-	-	-	-	ENERGY
7	TOTAL PLANT HELD FOR FUTURE USE	219,354	79,431	109,996	27,297	1,047	1,583	
8	CONSTRUCTION WORK IN PROGRESS							
9	PRODUCTION	-	-	-	-	-	-	PRODPLT
10	TRANSMISSION	-	-	-	-	-	-	TRANPLT
11	DISTRIBUTION	-	-	-	-	-	-	DISTPLTX
12	GENERAL	-	-	-	-	-	-	
13	FUEL	-	-	-	-	-	-	ENERGY
14	OTHER	-	-	-	-	-	-	GENPLT
15	TOTAL GENERAL	-	-	-	-	-	-	
16	TOTAL CONSTRUCTION WORK IN PROGRESS	-	-	-	-	-	-	
17	WORKING CAPITAL							
18	MATERIALS & SUPPLIES							
19	PRODUCTION	5,381,165	2,170,047	2,590,509	569,332	22,703	28,574	PRODPLT
20	TRANSMISSION	3,633,737	1,408,486	1,762,505	444,573	17,444	730	TRANPLT
21	DISTRIBUTION	4,067,087	1,865,039	1,840,327	146,258	24,303	191,160	DISTPLT
22	TOT PLANT MAT & SUPP	13,081,989	5,443,572	6,193,341	1,160,162	64,451	220,464	
23	PREPAYMENTS	-	-	-	-	-	-	
24	FAS 87 PENSION	28,351,481	12,711,729	12,213,304	2,562,284	149,802	714,362	LABORT
25	INSURANCE/MISC/AR FAC	-	-	-	-	-	-	RBX

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TOTAL AR RETAIL JURISDICTION	RESIDENTIAL	COMMERCIAL / SMALL INDUSTRIAL	LARGE INDUSTRIAL	MUNICIPAL	LIGHTING	ALLOC
		(1)	(2)	(3)	(4)	(5)	(6)	
26	FUEL RELATED	-	-	-	-	-	-	ENERGY
27	PLANT	-	-	-	-	-	-	PLANT
28	TOTAL PREPAYMENTS	28,351,481	12,711,729	12,213,304	2,562,284	149,802	714,362	
29	FUEL INVENTORY	11,879,984	3,592,681	6,302,857	1,799,571	66,257	118,617	ENERGY
30	MISCELLANEOUS WORKING CAP	122,214,204	50,776,502	57,779,109	10,785,196	615,787	2,257,610	RBX
31	TOTAL WORKING CAPITAL	175,527,657	72,524,484	82,488,611	16,307,212	896,296	3,311,054	
32	PLANT ACQ ADJ NET	-	-	-	-	-	-	DISTPLTLA
33	OTHER ADDITIONS TO RATE BASE							
34	AMAX COAL CONTRACT	-	-	-	-	-	-	ENERGY
35	FUEL LITIGATION DOCKET U23029	-	-	-	-	-	-	KWHLA
36	DEFERRED DSM COSTS DOCKET U23029	-	-	-	-	-	-	DPRODLA
37	TRADING DEPOSITS	-	-	-	-	-	-	REVFUEL
38	AVAILABLE	-	-	-	-	-	-	LABORT
39	AVAILABLE	-	-	-	-	-	-	PRODPLTR
40	AVAILABLE	-	-	-	-	-	-	PRODPLT
41	AVAILABLE	-	-	-	-	-	-	PRODPLTR
42	AVAILABLE	-	-	-	-	-	-	REVSALELA
43	TOTAL OTHER ADDITIONS TO RATE BASE	-	-	-	-	-	-	
44	TOTAL ADDITIONS-RATE-BASE	175,747,011	72,603,915	82,598,607	16,334,509	897,343	3,312,637	

SCHEDULE G-2 ALLOCATION OF RATE BASE
DEDUCTIONS FROM RATE BASE

1	ACCUM DEFERRED INCOME TAX							
2	PRODUCTION	-	-	-	-	-	-	PRODPLT
3	CONTRA ADJ TO ADIT PROD	-	-	-	-	-	-	PRODPLT
4	NON AFUDC ADJ BASIS	-	-	-	-	-	-	
5	AFUDC ADJ TO ADIT - PROD	-	-	-	-	-	-	PRODPLT
6	TOTAL PROD ADIT	-	-	-	-	-	-	
7								
8	TRANSMISSION	-	-	-	-	-	-	TRANPLT
9	CONTRA ADJ TO ADIT TRAN	-	-	-	-	-	-	TRANPLT
10	NON AFUDC ADJ BASIS	-	-	-	-	-	-	
11	AFUDC ADJ TO ADIT - TRAN	-	-	-	-	-	-	TRANPLT
12	TOTAL TRAN ADIT	-	-	-	-	-	-	
13								

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TOTAL AR RETAIL JURISDICTION	RESIDENTIAL	COMMERCIAL / SMALL INDUSTRIAL	LARGE INDUSTRIAL	MUNICIPAL	LIGHTING	ALLOC
		(1)	(2)	(3)	(4)	(5)	(6)	
14	DISTRIBUTION	-	-	-	-	-	-	DISTPLT
15	CONTRA ADJ TO ADIT DIST	-	-	-	-	-	-	DISTPLT
16	NON AFUDC ADJ BASIS	-	-	-	-	-	-	
17	AFUDC ADJ TO ADIT - DIST	-	-	-	-	-	-	DISTPLT
18	TOTAL DIST ADIT	-	-	-	-	-	-	
19								
20	GENERAL	-	-	-	-	-	-	GENPLT
21	CONTRA ADJ TO ADIT GEN	-	-	-	-	-	-	GENPLT
22	NON AFUDC ADJ BASIS	-	-	-	-	-	-	
23	AFUDC ADJ TO ADIT - GEN	-	-	-	-	-	-	GENPLT
24	TOTAL GEN ADIT	-	-	-	-	-	-	

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TOTAL AR RETAIL JURISDICTION (1)	RESIDENTIAL (2)	COMMERCIAL / SMALL INDUSTRIAL (3)	LARGE INDUSTRIAL (4)	MUNICIPAL (5)	LIGHTING (6)	ALLOC
	SCHEDULE G-2 ALLOCATION OF RATE BASE							
	DEDUCTIONS FROM RATE BASE							
1	PLANT RELATED	-	-	-	-	-	-	PLANT
2	PLANT RELATED	-	-	-	-	-	-	PLANT
3	PLANT RELATED	-	-	-	-	-	-	PLANT
4	PLANT RELATED	-	-	-	-	-	-	PLANT
5	PLANT RELATED	-	-	-	-	-	-	PLANT
6	PLANT RELATED	-	-	-	-	-	-	PLANT
7	PLANT RELATED	-	-	-	-	-	-	PLANT
8	PLANT RELATED	-	-	-	-	-	-	PLANT
9	PLANT RELATED	-	-	-	-	-	-	PLANT
10		-	-	-	-	-	-	PLANT
11	TOTAL ACCUM DEF INC TAX	-	-	-	-	-	-	
12								
13	CUSTOMER DEPOSITS	-	-	-	-	-	-	CUSTDEPA
14								
15	PRE-1971 ITC	-	-	-	-	-	-	NETPLT
16								
17	OTHER DEDUCTIONS							
18	MISC DEPOSITS	-	-	-	-	-	-	TRANPLT
19	BREMCO LIABILITY	-	-	-	-	-	-	DISTPLTLA
20	POLE ATTACH & MISC PROCEEDS	-	-	-	-	-	-	DISTPLT
21	TOTAL OTHER DEDUCTIONS	-	-	-	-	-	-	
22								
23	TOTAL DEDUCTIONS-RATE BASE	-	-	-	-	-	-	
24								
25	TOTAL RATE BASE	1,181,137,178	490,728,678	558,405,252	104,233,350	5,951,260	21,818,638	

Supporting Schedules
(a) B-1
(b) G-4
(c) F-1.3
WP's G-2
WP's G-2 and G-3
G Class WP

Recap Schedules
(A) G-1

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

			RESIDENTIAL					COMMERCIAL / SMALL INDUS			
			BASIC	WITH WATER HEAT	WITH SPACE HEAT	TOTAL RESIDENTIAL	GENERAL UNMETERED	LIGHT & POWER PRI	LIGHT & POWER SEC	PRIMARY SUB	GENERAL SERVICE
			(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	FERC ACCT	SCHEDULE G-2 ALLOCATION OF RATE BASE ELECTRIC PLANT IN SERVICE									
1		PROD - INTANGIBLE PLANT	3,687,104		666,047	4,353,151		1,394,822	3,292,916		1,288,263
2		TRAN - INTANGIBLE PLANT	1,737,107		360,166	2,097,273		625,254	1,427,981		550,282
3		DIST - INTANGIBLE PLANT	4,927,029		979,290	5,906,319		865,144	3,399,607		1,681,794
4		TOTAL INTANGIBLE PLANT	10,351,240		2,005,503	12,356,744		2,885,220	8,120,504		3,520,339
5											
6		PRODUCTION PLANT									
7		UNADJUSTED PRODUCTION PLANT	208,374,587		33,854,729	242,229,315		60,239,577	159,453,957		67,504,630
8		CONTRA ADJ TO EPIS - PROD	-		-	-		-	-		-
9		NON-AFUDC ADJUSTED VALUE	208,374,587		33,854,729	242,229,315		60,239,577	159,453,957		67,504,630
10		AFUDC ADJ TO EPIS-PROD	2,977,235		483,713	3,460,948		860,697	2,278,262		964,499
11		TOTAL PRODUCTION PLANT	211,351,821		34,338,441	245,690,263		61,100,273	161,732,219		68,469,129
12											
13		TRANSMISSION PLANT									
14	350	350-LAND & LAND RIGHTS	7,123,824		1,477,032	8,600,857		2,564,149	5,856,111		2,256,692
15	352	352-STRUCTURES & IMPROVEMENTS	1,082,814		224,507	1,307,322		389,748	890,123		343,015
16	352	352-STRUCTURES & IMPROVEMENTS GEN	-		-	-		-	-		-
17	353	353-STATION EQUIPMENT	45,024,860		9,335,320	54,360,180		16,206,247	37,012,503		14,263,018
18	353	353-STATION EQUIPMENT GEN	-		-	-		-	-		-
19	354	354-TOWERS & FIXTURES	3,007,078		623,479	3,630,557		1,082,368	2,471,956		952,585
20	355	355-POLES & FIXTURES	47,627,284		9,874,899	57,502,183		17,142,963	39,151,814		15,087,416
21	356	356-OVERHEAD CONDUCTORS & DEVICES	27,994,974		5,804,394	33,799,368		10,076,510	23,013,154		8,868,275
22	357	357-UNDERGROUND CONDUIT	152,238		31,565	183,803		54,797	125,147		48,226
23	358	358-UNDERGROUND COND & DEVICES	2,966		615	3,581		1,067	2,438		939
24	359	359- ROADS AND TRAILS	8,706		1,805	10,511		3,134	7,157		2,758
25		UNADJUSTED TRANSMISSION PLANT	132,024,744		27,373,616	159,398,361		47,520,983	108,530,403		41,822,925
26		CONTRA ADJ TO EPIS-TRANS	-		-	-		-	-		-
27		NON-AFUDC ADJUSTED VALUE	132,024,744		27,373,616	159,398,361		47,520,983	108,530,403		41,822,925
28		AFUDC ADJ TO EPIS - TRANS	56,951		11,808	68,759		20,499	46,816		18,041
29		TOTAL TRANSMISSION PLANT	132,081,695		27,385,425	159,467,120		47,541,482	108,577,219		41,840,966
1		DISTRIBUTION PLANT									
2	360	360-LAND & LAND RIGHTS	985,200		199,538	1,184,738		286,241	735,568		340,774
3	361	361-STRUCTURES & IMPROVEMENTS	896,054		181,483	1,077,537		260,341	669,010		309,939

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

			RESIDENTIAL					COMMERCIAL / SMALL INDUS			
			BASIC	WITH WATER HEAT	WITH SPACE HEAT	TOTAL RESIDENTIAL	GENERAL UNMETERED	LIGHT & POWER PRI	LIGHT & POWER SEC	LIGHT & POWER PRIMARY SUB	GENERAL SERVICE
			(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
4	362	362-STATION EQUIPMENT	28,796,431		5,832,303	34,628,734		8,366,555	21,499,935		9,960,477
5	364	364-POLES TOWERS & FIXTURES									
6		PRIMARY	18,139,592		3,673,914	21,813,506		5,270,302	13,543,347		6,274,354
7		SECONDARY	15,447,735		3,128,717	18,576,452		-	11,533,558		5,343,260
8		TOTAL ACCOUNT 364	33,587,328		6,802,630			5,270,302	25,076,905		11,617,613
9	365	365-OVERHEAD CONDUCTORS & DEVICES									
10		PRIMARY	25,939,869		5,253,748	31,193,617		7,536,605	19,367,175		8,972,413
11		SECONDARY	10,458,907		2,118,301	12,577,209		-	7,808,809		3,617,660
12		TOTAL ACCOUNT 365	36,398,777		7,372,049			7,536,605	27,175,984		12,590,073
13	366	366-UNDERGROUND CONDUIT									
14		PRIMARY	2,774,489		561,933	3,336,422		806,104	2,071,484		959,676
15		SECONDARY	3,696,778		748,729	4,445,508		-	2,760,081		1,278,689
16		TOTAL ACCOUNT 366	6,471,268		1,310,662			806,104	4,831,565		2,238,365
17	367	367-UNDERGROUND CONDUCTORS & DEV.									
18		PRIMARY	9,666,397		1,957,790	11,624,187		2,808,488	7,217,106		3,343,537
19		SECONDARY	12,879,677		2,608,593	15,488,271		-	9,616,199		4,454,987
20		TOTAL ACCOUNT 367	22,546,074		4,566,383			2,808,488	16,833,306		7,798,524
21	368	368-LINE TRANSFORMERS	21,217,918		4,297,384	25,515,303		6,164,683	15,841,681		7,339,124
22	369	369-SERVICES	15,302,174		2,437,491	17,739,666		24,118	542,480		3,294,205
23	370	370-METERS	10,608,733		1,685,630	12,294,363		420,559	1,595,969		3,882,571
24	371	371-INSTALLATIONS	-		-	-		-	-		-
25	373	373-STREET LIGHTS	-		-	-		-	-		-
26		UNADJUSTED DISTRIBUTION PLANT	176,809,957		34,685,554	211,495,512		31,943,996	114,802,403		59,371,663
27		CONTRA ADJ TO EPIS- DIST	-		-	-		-	-		-
28		NON-AFUDC ADJUSTED VALUE	176,809,957		34,685,554	211,495,512		31,943,996	114,802,403		59,371,663
29		AFUDC ADJ TO EPIS - DIST	(282,515)		(55,422)	(337,937)		(51,041)	(183,436)		(94,867)
30		TOTAL DISTRIBUTION PLANT	176,527,443		34,630,132	211,157,575		31,892,955	114,618,967		59,276,796
		SCHEDULE G-2 ALLOCATION OF RATE BASE									
		ELECTRIC PLANT IN SERVICE									
1		GENERAL PLANT									
2		GENERAL PLANT	18,747,990		3,386,681	22,134,671		7,092,315	16,743,643		6,550,492
3		ENERGY	-		-	-		-	-		-
4		TRANSMISSION	-		-	-		-	-		-
5		DISTRIBUTION	-		-	-		-	-		-
6		CAPITAL LEASE ASSETS Net	-		-	-		-	-		-

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CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		RESIDENTIAL				COMMERCIAL / SMALL INDUS				
		BASIC	WITH WATER HEAT	WITH SPACE HEAT	TOTAL RESIDENTIAL	GENERAL UNMETERED	LIGHT & POWER PRI	LIGHT & POWER SEC	PRIMARY SUB	GENERAL SERVICE
		(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
7	OTHER	-		-	-		-	-		-
8	OTHER	-		-	-		-	-		-
9	UNADJUSTED GENERAL PLANT	18,747,990		3,386,681	22,134,671		7,092,315	16,743,643		6,550,492
10	CONTRA ADJ TO EPIS- GENERAL PLT	-		-	-		-	-		-
11	NON-AFUDC ADJUSTED VALUE	18,747,990		3,386,681	22,134,671		7,092,315	16,743,643		6,550,492
12	AFUDC ADJ TO EPIS - GENERAL - FUEL RELAT	-		-	-		-	-		-
13	AFUDC ADJ TO EPIS - GENERAL - NON FUEL	-		-	-		-	-		-
14	TOTAL GENERAL PLANT	18,747,990		3,386,681	22,134,671		7,092,315	16,743,643		6,550,492
15					-					
16	TOTAL ELEC PLANT IN SERVICE	549,060,190		101,746,183	650,806,372		150,512,245	409,792,553		179,657,723

SCHEDULE G-2 ALLOCATION OF RATE BASE
ELECTRIC PLANT IN SERVICE

		(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	LESS: RESERVE FOR DEPRECIATION									
2	PRODUCTION PLANT	104,475,998		16,974,270	121,450,268		30,203,251	79,947,903		33,845,843
3	CONTRA ADJ TO DEPR - PROD	-		-	-		-	-		-
4	NON-AFUDC ADJUSTED VALUE	104,475,998		16,974,270	121,450,268		30,203,251	79,947,903		33,845,843
5	AFUDC ADJ TO DEPR - PROD	-		-	-		-	-		-
6	TOTAL PROD ACCUM DEPR	104,475,998		16,974,270	121,450,268		30,203,251	79,947,903		33,845,843
7	TRANSMISSION PLANT	33,135,962		6,870,311	40,006,273		11,926,957	27,239,282		10,496,842
8	CONTRA ADJ TO DEPR - TRAN	-		-	-		-	-		-
9	NON-AFUDC ADJUSTED VALUE	33,135,962		6,870,311	40,006,273		11,926,957	27,239,282		10,496,842
10	AFUDC ADJ TO DEPR - TRAN	-		-	-		-	-		-
11	TOTAL TRAN ACCUM DEPR	33,135,962		6,870,311	40,006,273		11,926,957	27,239,282		10,496,842
12	DISTRIBUTION PLANT	46,413,914		9,105,213	55,519,126		8,385,534	30,136,475		15,585,498
13	CONTRA ADJ TO DEPR - DIST	-		-	-		-	-		-
14	NON-AFUDC ADJUSTED VALUE	46,413,914		9,105,213	55,519,126		8,385,534	30,136,475		15,585,498
15	AFUDC ADJ TO DEPR - DIST	-		-	-		-	-		-
16	TOTAL DIST ACCUM DEPR	46,413,914		9,105,213	55,519,126		8,385,534	30,136,475		15,585,498
17	GENERAL PLANT									
18	GENERAL	9,632,594		1,740,055	11,372,648		3,643,984	8,602,774		3,365,600
19	GENERAL FUEL	-		-	-		-	-		-
20	TRANSPORTATION	-		-	-		-	-		-
21	RWIP GENERATION	-		-	-		-	-		-
22	RWIP TRANSMISSION	-		-	-		-	-		-
23	RWIP DISTRIBUTION	-		-	-		-	-		-

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		RESIDENTIAL					COMMERCIAL / SMALL INDUS			
		BASIC	WITH WATER HEAT	WITH SPACE HEAT	TOTAL RESIDENTIAL	GENERAL UNMETERED	LIGHT & POWER PRI	LIGHT & POWER SEC	PRIMARY SUB	GENERAL SERVICE
		(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
24	INTANGIBLE	3,629,999		703,295	4,333,293		1,011,796	2,847,719		1,234,521
25	TOTAL GENERAL PLANT	13,262,592		2,443,349	15,705,942		4,655,781	11,450,492		4,600,121
26	CONTRA ADJ TO DEPR - GENL	-		-	-		-	-		-
27	NON-AFUDC ADJUSTED VALUE	13,262,592		2,443,349	15,705,942		4,655,781	11,450,492		4,600,121
28	AFUDC ADJ TO DEPR - GENL	-		-	-		-	-		-
29	TOTAL GENL ACCUM DEPR	13,262,592		2,443,349	15,705,942		4,655,781	11,450,492		4,600,121
30	TOT ACCUM PROV FOR DEPR	197,288,465		35,393,144	232,681,609		55,171,522	148,774,152		64,528,304
31	NET ELECTRIC PLANT IN SERVICE	351,771,725		66,353,039	418,124,763		95,340,723	261,018,401		115,129,419
WORKPAPER E										
	ADDITIONS TO RATE BASE									
1	PLANT HELD FOR FUTURE USE									
2	PRODUCTION	-		-	-		-	-		-
3	TRANSMISSION	-		-	-		-	-		-
4	DISTRIBUTION	-		-	-		-	-		-
5	GENERAL	67,277		12,153	79,431		25,451	60,085		23,507
6	LIGNITE	-		-	-		-	-		-
7	TOTAL PLANT HELD FOR FUTURE USE	67,277		12,153	79,431		25,451	60,085		23,507
8	CONSTRUCTION WORK IN PROGRESS									
9	PRODUCTION	-		-	-		-	-		-
10	TRANSMISSION	-		-	-		-	-		-
11	DISTRIBUTION	-		-	-		-	-		-
12	GENERAL									
13	FUEL	-		-	-		-	-		-
14	OTHER	-		-	-		-	-		-
15	TOTAL GENERAL	-		-			-	-		-
16	TOTAL CONSTRUCTION WORK IN PROGRESS	-		-			-	-		-
17	WORKING CAPITAL									
18	MATERIALS & SUPPLIES									
19	PRODUCTION	1,866,755		303,293	2,170,047		539,665	1,428,492		604,750
20	TRANSMISSION	1,166,605		241,880	1,408,486		419,908	959,003		369,558
21	DISTRIBUTION	1,559,170		305,869	1,865,039		281,693	1,012,366		523,559
22	TOT PLANT MAT & SUPP	4,592,530		851,042	5,443,572		1,241,266	3,399,861		1,497,868
23	PREPAYMENTS									
24	FAS 87 PENSION	10,791,508		1,920,221	12,711,729		2,417,372	6,376,833		3,260,636
25	INSURANCE/MISC/AR FAC	-		-	-		-	-		-

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		RESIDENTIAL				COMMERCIAL / SMALL INDUS				
		BASIC	WITH WATER HEAT	WITH SPACE HEAT	TOTAL RESIDENTIAL	GENERAL UNMETERED	LIGHT & POWER PRI	LIGHT & POWER SEC	PRIMARY SUB	GENERAL SERVICE
		(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
26	FUEL RELATED	-		-	-		-	-		-
27	PLANT	-		-	-		-	-		-
28	TOTAL PREPAYMENTS	10,791,508		1,920,221	12,711,729		2,417,372	6,376,833		3,260,636
29	FUEL INVENTORY	2,950,981		641,700	3,592,681		1,649,598	3,399,832		1,183,134
30	MISCELLANEOUS WORKING CAP	42,723,148		8,053,354	50,776,502		11,619,205	31,652,782		13,975,970
31	TOTAL WORKING CAPITAL	61,058,167		11,466,317	72,524,484		16,927,440	44,829,309		19,917,608
32	PLANT ACQ ADJ NET	-		-	-		-	-		-
33	OTHER ADDITIONS TO RATE BASE									
34	AMAX COAL CONTRACT	-		-	-		-	-		-
35	FUEL LITIGATION DOCKET U23029	-		-	-		-	-		-
36	DEFERRED DSM COSTS DOCKET U23029	-		-	-		-	-		-
37	TRADING DEPOSITS	-		-	-		-	-		-
38	AVAILABLE	-		-	-		-	-		-
39	AVAILABLE	-		-	-		-	-		-
40	AVAILABLE	-		-	-		-	-		-
41	AVAILABLE	-		-	-		-	-		-
42	AVAILABLE	-		-	-		-	-		-
43	TOTAL OTHER ADDITIONS TO RATE BASE	-		-	-		-	-		-
44	TOTAL ADDITIONS-RATE-BASE	61,125,444		11,478,470	72,603,915		16,952,891	44,889,394		19,941,114
	SCHEDULE G-2 ALLOCATION OF RATE BASE									
	DEDUCTIONS FROM RATE BASE									
1	ACCUM DEFERRED INCOME TAX									
2	PRODUCTION	-		-	-		-	-		-
3	CONTRA ADJ TO ADIT PROD	-		-	-		-	-		-
4	NON AFUDC ADJ BASIS	-		-			-	-		-
5	AFUDC ADJ TO ADIT - PROD	-		-	-		-	-		-
6	TOTAL PROD ADIT	-		-			-	-		-
7										
8	TRANSMISSION	-		-	-		-	-		-
9	CONTRA ADJ TO ADIT TRAN	-		-	-		-	-		-
10	NON AFUDC ADJ BASIS	-		-			-	-		-
11	AFUDC ADJ TO ADIT - TRAN	-		-	-		-	-		-
12	TOTAL TRAN ADIT	-		-			-	-		-
13										

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		RESIDENTIAL				COMMERCIAL / SMALL INDUS				
							LIGHT & POWER			
		BASIC	WITH WATER HEAT	WITH SPACE HEAT	TOTAL RESIDENTIAL	GENERAL UNMETERED	PRI	SEC	PRIMARY SUB	GENERAL SERVICE
		(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
14	DISTRIBUTION	-		-	-		-	-		-
15	CONTRA ADJ TO ADIT DIST	-		-	-		-	-		-
16	NON AFUDC ADJ BASIS	-		-			-	-		-
17	AFUDC ADJ TO ADIT - DIST	-		-	-		-	-		-
18	TOTAL DIST ADIT	-		-			-	-		-
19										
20	GENERAL	-		-	-		-	-		-
21	CONTRA ADJ TO ADIT GEN	-		-	-		-	-		-
22	NON AFUDC ADJ BASIS	-		-			-	-		-
23	AFUDC ADJ TO ADIT - GEN	-		-	-		-	-		-
24	TOTAL GEN ADIT	-		-			-	-		-

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		RESIDENTIAL				COMMERCIAL / SMALL INDUS				
		BASIC	WITH WATER HEAT	WITH SPACE HEAT	TOTAL RESIDENTIAL	GENERAL UNMETERED	LIGHT & POWER PRI	LIGHT & POWER SEC	PRIMARY SUB	GENERAL SERVICE
		(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	SCHEDULE G-2 ALLOCATION OF RATE BASE									
	DEDUCTIONS FROM RATE BASE									
1	PLANT RELATED	-		-	-		-	-		-
2	PLANT RELATED	-		-	-		-	-		-
3	PLANT RELATED	-		-	-		-	-		-
4	PLANT RELATED	-		-	-		-	-		-
5	PLANT RELATED	-		-	-		-	-		-
6	PLANT RELATED	-		-	-		-	-		-
7	PLANT RELATED	-		-	-		-	-		-
8	PLANT RELATED	-		-	-		-	-		-
9	PLANT RELATED	-		-	-		-	-		-
10		-		-	-		-	-		-
11	TOTAL ACCUM DEF INC TAX	-		-			-	-		-
12										
13	CUSTOMER DEPOSITS	-		-	-		-	-		-
14										
15	PRE-1971 ITC	-		-	-		-	-		-
16										
17	OTHER DEDUCTIONS									
18	MISC DEPOSITS	-		-	-		-	-		-
19	BREMCO LIABILITY	-		-	-		-	-		-
20	POLE ATTACH & MISC PROCEEDS	-		-	-		-	-		-
21	TOTAL OTHER DEDUCTIONS	-		-	-		-	-		-
22										
23	TOTAL DEDUCTIONS-RATE BASE	-		-	-		-	-		-
24										
25	TOTAL RATE BASE	412,897,169		77,831,509	490,728,678		112,293,614	305,907,794		135,070,534

Supporting Schedules
(a) B-1
(b) G-4
(c) F-1.3
WP's G-2
WP's G-2 and G-3
G Class WP

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Schedule: G-2
Cost of Service Study - Rate Base Detail
Class

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

			TRIAL				LARGE INDUSTRIAL				
			C-1	LIGHT & POWER TOU			LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY
			RIDER	SEC	PRI	TOTAL	PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE
			(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
	FERC ACCT	SCHEDULE G-2 ALLOCATION OF RATE BASE ELECTRIC PLANT IN SERVICE									
1		PROD - INTANGIBLE PLANT		15,823	36,481	52,303	489,319	356,702	846,021	577,840	72,121
2		TRAN - INTANGIBLE PLANT		7,597	13,303	20,899	211,994	158,794	370,789	251,145	40,047
3		DIST - INTANGIBLE PLANT		47,435	26,648	74,083	345,090	1,031	346,121	1,034	102,544
4		TOTAL INTANGIBLE PLANT		70,854	76,431	147,285	1,046,402	516,527	1,562,930	830,019	214,712
5											
6		PRODUCTION PLANT									
7		UNADJUSTED PRODUCTION PLANT		657,729	1,307,049	1,964,778	22,929,217	13,967,884	36,897,101	23,598,359	3,055,587
8		CONTRA ADJ TO EPIS - PROD		-	-	-	-	-	-	-	-
9		NON-AFUDC ADJUSTED VALUE		657,729	1,307,049	1,964,778	22,929,217	13,967,884	36,897,101	23,598,359	3,055,587
10		AFUDC ADJ TO EPIS-PROD		9,398	18,675	28,073	327,610	199,572	527,182	337,171	43,658
11		TOTAL PRODUCTION PLANT		667,127	1,325,724	1,992,851	23,256,828	14,167,455	37,424,283	23,935,530	3,099,245
12											
13		TRANSMISSION PLANT									
14	350	350-LAND & LAND RIGHTS		31,154	54,554	85,708	869,382	651,211	1,520,593	1,029,940	164,230
15	352	352-STRUCTURES & IMPROVEMENTS		4,735	8,292	13,028	132,145	98,983	231,129	156,550	24,963
16	352	352-STRUCTURES & IMPROVEMENTS GEN		-	-	-	-	-	-	-	-
17	353	353-STATION EQUIPMENT		196,906	344,796	541,703	5,494,774	4,115,866	9,610,640	6,509,551	1,037,986
18	353	353-STATION EQUIPMENT GEN		-	-	-	-	-	-	-	-
19	354	354-TOWERS & FIXTURES		13,151	23,028	36,179	366,980	274,887	641,866	434,754	69,324
20	355	355-POLES & FIXTURES		208,287	364,726	573,013	5,812,371	4,353,761	10,166,132	6,885,801	1,097,981
21	356	356-OVERHEAD CONDUCTORS & DEVICES		122,430	214,383	336,813	3,416,470	2,559,110	5,975,579	4,047,424	645,385
22	357	357-UNDERGROUND CONDUIT		666	1,166	1,832	18,579	13,917	32,496	22,010	3,510
23	358	358-UNDERGROUND COND & DEVICES		13	23	36	362	271	633	429	68
24	359	359- ROADS AND TRAILS		38	67	105	1,063	796	1,858	1,259	201
25		UNADJUSTED TRANSMISSION PLANT		577,381	1,011,034	1,588,415	16,112,125	12,068,801	28,180,927	19,087,716	3,043,648
26		CONTRA ADJ TO EPIS-TRANS		-	-	-	-	-	-	-	-
27		NON-AFUDC ADJUSTED VALUE		577,381	1,011,034	1,588,415	16,112,125	12,068,801	28,180,927	19,087,716	3,043,648
28		AFUDC ADJ TO EPIS - TRANS		249	436	685	6,950	5,206	12,156	8,234	1,313
29		TOTAL TRANSMISSION PLANT		577,630	1,011,470	1,589,100	16,119,075	12,074,007	28,193,083	19,095,950	3,044,961
1		DISTRIBUTION PLANT									
2	360	360-LAND & LAND RIGHTS		10,374	8,851	19,225	115,275	-	115,275	-	33,989
3	361	361-STRUCTURES & IMPROVEMENTS		9,436	8,050	17,485	104,844	-	104,844	-	30,913

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

			TRIAL				LARGE INDUSTRIAL				
			C-1	LIGHT & POWER TOU			LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY
			RIDER	SEC	PRI	TOTAL	PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE
			(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
4	362	362-STATION EQUIPMENT		303,230	258,700	561,929	3,369,375	-	3,369,375	-	993,451
5	364	364-POLES TOWERS & FIXTURES									
6		PRIMARY		191,012	162,961	353,973	2,122,454	-	2,122,454	-	625,800
7		SECONDARY		162,666	-	162,666	-	-	-	-	-
8		TOTAL ACCOUNT 364		353,678	162,961		2,122,454	-		-	625,800
9	365	365-OVERHEAD CONDUCTORS & DEVICES									
10		PRIMARY		273,150	233,037	506,187	3,035,138	-	3,035,138	-	894,902
11		SECONDARY		110,133	-	110,133	-	-	-	-	-
12		TOTAL ACCOUNT 365		383,283	233,037		3,035,138	-		-	894,902
13	366	366-UNDERGROUND CONDUIT									
14		PRIMARY		29,216	24,925	54,141	324,634	-	324,634	-	95,717
15		SECONDARY		38,927	-	38,927	-	-	-	-	-
16		TOTAL ACCOUNT 366		68,143	24,925		324,634	-		-	95,717
17	367	367-UNDERGROUND CONDUCTORS & DEV.									
18		PRIMARY		101,788	86,840	188,629	1,131,033	-	1,131,033	-	333,482
19		SECONDARY		135,624	-	135,624	-	-	-	-	-
20		TOTAL ACCOUNT 367		237,413	86,840		1,131,033	-		-	333,482
21	368	368-LINE TRANSFORMERS		223,427	190,616	414,043	2,482,639	-	2,482,639	-	731,999
22	369	369-SERVICES		1,049	524	1,573	1,049	-	1,049	-	2,622
23	370	370-METERS		2,302	8,239	10,541	16,478	49,192	65,671	49,314	41,317
24	371	371-INSTALLATIONS		-	-	-	-	-	-	-	-
25	373	373-STREET LIGHTS		-	-	-	-	-	-	-	-
26		UNADJUSTED DISTRIBUTION PLANT		1,592,335	982,744	2,575,078	12,702,919	49,192	12,752,112	49,314	3,784,192
27		CONTRA ADJ TO EPIS- DIST		-	-	-	-	-	-	-	-
28		NON-AFUDC ADJUSTED VALUE		1,592,335	982,744	2,575,078	12,702,919	49,192	12,752,112	49,314	3,784,192
29		AFUDC ADJ TO EPIS - DIST		(2,544)	(1,570)	(4,115)	(20,297)	(79)	(20,376)	(79)	(6,047)
30		TOTAL DISTRIBUTION PLANT		1,589,790	981,173	2,570,964	12,682,622	49,114	12,731,736	49,235	3,778,146
		SCHEDULE G-2 ALLOCATION OF RATE BASE									
		ELECTRIC PLANT IN SERVICE									
1		GENERAL PLANT									
2		GENERAL PLANT		80,453	185,495	265,948	2,488,062	1,813,739	4,301,801	2,938,168	366,718
3		ENERGY		-	-	-	-	-	-	-	-
4		TRANSMISSION		-	-	-	-	-	-	-	-
5		DISTRIBUTION		-	-	-	-	-	-	-	-
6		CAPITAL LEASE ASSETS Net		-	-	-	-	-	-	-	-

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TRIAL				LARGE INDUSTRIAL				
		C-1	LIGHT & POWER TOU			LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY
		RIDER	SEC	PRI	TOTAL	PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE
		(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
7	OTHER		-	-	-	-	-	-	-	-
8	OTHER		-	-	-	-	-	-	-	-
9	UNADJUSTED GENERAL PLANT		80,453	185,495	265,948	2,488,062	1,813,739	4,301,801	2,938,168	366,718
10	CONTRA ADJ TO EPIS- GENERAL PLT		-	-	-	-	-	-	-	-
11	NON-AFUDC ADJUSTED VALUE		80,453	185,495	265,948	2,488,062	1,813,739	4,301,801	2,938,168	366,718
12	AFUDC ADJ TO EPIS - GENERAL - FUEL RELAT		-	-	-	-	-	-	-	-
13	AFUDC ADJ TO EPIS - GENERAL - NON FUEL		-	-	-	-	-	-	-	-
14	TOTAL GENERAL PLANT		80,453	185,495	265,948	2,488,062	1,813,739	4,301,801	2,938,168	366,718
15										
16	TOTAL ELEC PLANT IN SERVICE		2,985,855	3,580,294	6,566,148	55,592,990	28,620,843	84,213,833	46,848,901	10,503,782
	SCHEDULE G-2 ALLOCATION OF RATE BASE									
	ELECTRIC PLANT IN SERVICE									
1	LESS: RESERVE FOR DEPRECIATION									
2	PRODUCTION PLANT		329,776	655,335	985,111	11,496,377	7,003,294	18,499,672	11,831,875	1,532,027
3	CONTRA ADJ TO DEPR - PROD		-	-	-	-	-	-	-	-
4	NON-AFUDC ADJUSTED VALUE		329,776	655,335	985,111	11,496,377	7,003,294	18,499,672	11,831,875	1,532,027
5	AFUDC ADJ TO DEPR - PROD		-	-	-	-	-	-	-	-
6	TOTAL PROD ACCUM DEPR		329,776	655,335	985,111	11,496,377	7,003,294	18,499,672	11,831,875	1,532,027
7	TRANSMISSION PLANT		144,913	253,752	398,665	4,043,869	3,029,064	7,072,932	4,790,692	763,904
8	CONTRA ADJ TO DEPR - TRAN		-	-	-	-	-	-	-	-
9	NON-AFUDC ADJUSTED VALUE		144,913	253,752	398,665	4,043,869	3,029,064	7,072,932	4,790,692	763,904
10	AFUDC ADJ TO DEPR - TRAN		-	-	-	-	-	-	-	-
11	TOTAL TRAN ACCUM DEPR		144,913	253,752	398,665	4,043,869	3,029,064	7,072,932	4,790,692	763,904
12	DISTRIBUTION PLANT		418,000	257,977	675,977	3,334,610	12,913	3,347,523	12,945	993,378
13	CONTRA ADJ TO DEPR - DIST		-	-	-	-	-	-	-	-
14	NON-AFUDC ADJUSTED VALUE		418,000	257,977	675,977	3,334,610	12,913	3,347,523	12,945	993,378
15	AFUDC ADJ TO DEPR - DIST		-	-	-	-	-	-	-	-
16	TOTAL DIST ACCUM DEPR		418,000	257,977	675,977	3,334,610	12,913	3,347,523	12,945	993,378
17	GENERAL PLANT									
18	GENERAL		41,336	95,306	136,643	1,278,350	931,887	2,210,237	1,509,611	188,417
19	GENERAL FUEL		-	-	-	-	-	-	-	-
20	TRANSPORTATION		-	-	-	-	-	-	-	-
21	RWIP GENERATION		-	-	-	-	-	-	-	-
22	RWIP TRANSMISSION		-	-	-	-	-	-	-	-
23	RWIP DISTRIBUTION		-	-	-	-	-	-	-	-

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TRIAL				LARGE INDUSTRIAL				
		C-1	LIGHT & POWER TOU			LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY
		RIDER	SEC	PRI	TOTAL	PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE
		(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
24	INTANGIBLE		24,847	26,803	51,650	366,955	181,137	548,092	291,073	75,296
25	TOTAL GENERAL PLANT		66,184	122,109	188,293	1,645,305	1,113,024	2,758,329	1,800,684	263,713
26	CONTRA ADJ TO DEPR - GENL		-	-	-	-	-	-	-	-
27	NON-AFUDC ADJUSTED VALUE		66,184	122,109	188,293	1,645,305	1,113,024	2,758,329	1,800,684	263,713
28	AFUDC ADJ TO DEPR - GENL		-	-	-	-	-	-	-	-
29	TOTAL GENL ACCUM DEPR		66,184	122,109	188,293	1,645,305	1,113,024	2,758,329	1,800,684	263,713
30	TOT ACCUM PROV FOR DEPR		958,872	1,289,174	2,248,046	20,520,161	11,158,295	31,678,456	18,436,196	3,553,022
31	NET ELECTRIC PLANT IN SERVICE		2,026,983	2,291,119	4,318,102	35,072,829	17,462,547	52,535,376	28,412,705	6,950,759
WORKPAPER E										
	ADDITIONS TO RATE BASE									
1	PLANT HELD FOR FUTURE USE									
2	PRODUCTION		-	-	-	-	-	-	-	-
3	TRANSMISSION		-	-	-	-	-	-	-	-
4	DISTRIBUTION		-	-	-	-	-	-	-	-
5	GENERAL		289	666	954	8,928	6,509	15,437	10,544	1,316
6	LIGNITE		-	-	-	-	-	-	-	-
7	TOTAL PLANT HELD FOR FUTURE USE		289	666	954	8,928	6,509	15,437	10,544	1,316
8	CONSTRUCTION WORK IN PROGRESS									
9	PRODUCTION		-	-	-	-	-	-	-	-
10	TRANSMISSION		-	-	-	-	-	-	-	-
11	DISTRIBUTION		-	-	-	-	-	-	-	-
12	GENERAL									
13	FUEL		-	-	-	-	-	-	-	-
14	OTHER		-	-	-	-	-	-	-	-
15	TOTAL GENERAL		-	-		-	-		-	-
16	TOTAL CONSTRUCTION WORK IN PROGRESS		-	-		-	-		-	-
17	WORKING CAPITAL									
18	MATERIALS & SUPPLIES									
19	PRODUCTION		5,892	11,709	17,602	205,415	125,133	330,548	211,409	27,374
20	TRANSMISSION		5,102	8,934	14,036	142,371	106,643	249,014	168,664	26,894
21	DISTRIBUTION		14,042	8,666	22,708	112,019	434	112,452	435	33,370
22	TOT PLANT MAT & SUPP		25,036	29,309	54,345	459,804	232,210	692,015	380,508	87,639
23	PREPAYMENTS									
24	FAS 87 PENSION		77,513	80,949	158,463	911,879	533,732	1,445,611	885,081	231,592
25	INSURANCE/MISC/AR FAC		-	-	-	-	-	-	-	-

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TRIAL				LARGE INDUSTRIAL				
		C-1	LIGHT & POWER TOU			LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY
		RIDER	SEC	PRI	TOTAL	PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE
		(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
26	FUEL RELATED		-	-	-	-	-	-	-	-
27	PLANT		-	-	-	-	-	-	-	-
28	TOTAL PREPAYMENTS		77,513	80,949	158,463	911,879	533,732	1,445,611	885,081	231,592
29	FUEL INVENTORY		19,447	50,846	70,294	527,159	463,092	990,251	722,328	86,993
30	MISCELLANEOUS WORKING CAP		248,055	283,097	531,152	4,268,067	2,158,015	6,426,083	3,509,865	849,248
31	TOTAL WORKING CAPITAL		370,052	444,202	814,254	6,166,910	3,387,049	9,553,959	5,497,781	1,255,472
32	PLANT ACQ ADJ NET		-	-	-	-	-	-	-	-
33	OTHER ADDITIONS TO RATE BASE									
34	AMAX COAL CONTRACT		-	-	-	-	-	-	-	-
35	FUEL LITIGATION DOCKET U23029		-	-	-	-	-	-	-	-
36	DEFERRED DSM COSTS DOCKET U23029		-	-	-	-	-	-	-	-
37	TRADING DEPOSITS		-	-	-	-	-	-	-	-
38	AVAILABLE		-	-	-	-	-	-	-	-
39	AVAILABLE		-	-	-	-	-	-	-	-
40	AVAILABLE		-	-	-	-	-	-	-	-
41	AVAILABLE		-	-	-	-	-	-	-	-
42	AVAILABLE		-	-	-	-	-	-	-	-
43	TOTAL OTHER ADDITIONS TO RATE BASE		-	-	-	-	-	-	-	-
44	TOTAL ADDITIONS-RATE-BASE		370,340	444,868	815,208	6,175,838	3,393,558	9,569,396	5,508,325	1,256,788
	SCHEDULE G-2 ALLOCATION OF RATE BASE									
	DEDUCTIONS FROM RATE BASE									
1	ACCUM DEFERRED INCOME TAX									
2	PRODUCTION		-	-	-	-	-	-	-	-
3	CONTRA ADJ TO ADIT PROD		-	-	-	-	-	-	-	-
4	NON AFUDC ADJ BASIS		-	-		-	-		-	-
5	AFUDC ADJ TO ADIT - PROD		-	-	-	-	-	-	-	-
6	TOTAL PROD ADIT		-	-		-	-		-	-
7										
8	TRANSMISSION		-	-	-	-	-	-	-	-
9	CONTRA ADJ TO ADIT TRAN		-	-	-	-	-	-	-	-
10	NON AFUDC ADJ BASIS		-	-		-	-		-	-
11	AFUDC ADJ TO ADIT - TRAN		-	-	-	-	-	-	-	-
12	TOTAL TRAN ADIT		-	-		-	-		-	-
13										

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TRIAL				LARGE INDUSTRIAL				
		C-1	LIGHT & POWER TOU			LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY
		RIDER	SEC	PRI	TOTAL	PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE
		(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
14	DISTRIBUTION		-	-	-	-	-	-	-	-
15	CONTRA ADJ TO ADIT DIST		-	-	-	-	-	-	-	-
16	NON AFUDC ADJ BASIS		-	-		-	-		-	-
17	AFUDC ADJ TO ADIT - DIST		-	-	-	-	-	-	-	-
18	TOTAL DIST ADIT		-	-		-	-		-	-
19										
20	GENERAL		-	-	-	-	-	-	-	-
21	CONTRA ADJ TO ADIT GEN		-	-	-	-	-	-	-	-
22	NON AFUDC ADJ BASIS		-	-		-	-		-	-
23	AFUDC ADJ TO ADIT - GEN		-	-	-	-	-	-	-	-
24	TOTAL GEN ADIT		-	-		-	-		-	-

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TRIAL				LARGE INDUSTRIAL				
		C-1	LIGHT & POWER TOU			LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY
		RIDER	SEC	PRI	TOTAL	PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE
		(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
	SCHEDULE G-2 ALLOCATION OF RATE BASE									
	DEDUCTIONS FROM RATE BASE									
1	PLANT RELATED		-	-	-	-	-	-	-	-
2	PLANT RELATED		-	-	-	-	-	-	-	-
3	PLANT RELATED		-	-	-	-	-	-	-	-
4	PLANT RELATED		-	-	-	-	-	-	-	-
5	PLANT RELATED		-	-	-	-	-	-	-	-
6	PLANT RELATED		-	-	-	-	-	-	-	-
7	PLANT RELATED		-	-	-	-	-	-	-	-
8	PLANT RELATED		-	-	-	-	-	-	-	-
9	PLANT RELATED		-	-	-	-	-	-	-	-
10			-	-	-	-	-	-	-	-
11	TOTAL ACCUM DEF INC TAX		-	-		-	-		-	-
12										
13	CUSTOMER DEPOSITS		-	-	-	-	-	-	-	-
14										
15	PRE-1971 ITC		-	-	-	-	-	-	-	-
16										
17	OTHER DEDUCTIONS									
18	MISC DEPOSITS		-	-	-	-	-	-	-	-
19	BREMCO LIABILITY		-	-	-	-	-	-	-	-
20	POLE ATTACH & MISC PROCEEDS		-	-	-	-	-	-	-	-
21	TOTAL OTHER DEDUCTIONS		-	-	-	-	-	-	-	-
22										
23	TOTAL DEDUCTIONS-RATE BASE		-	-	-	-	-	-	-	-
24										
25	TOTAL RATE BASE		2,397,323	2,735,987	5,133,310	41,248,667	20,856,105	62,104,772	33,921,030	8,207,547

Supporting Schedules
(a) B-1
(b) G-4
(c) F-1.3
WP's G-2
WP's G-2 and G-3
G Class WP

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	FERC ACCT	SCHEDULE G-2 ALLOCATION OF RATE BASE ELECTRIC PLANT IN SERVICE		MUNICIPAL		LIGHTING			
			TOTAL (25)	PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
1		PROD - INTANGIBLE PLANT	649,961	40,946	16,436	26,337		60,430	86,767
2		TRAN - INTANGIBLE PLANT	291,192	18,289	7,686	325		762	1,087
3		DIST - INTANGIBLE PLANT	103,578	55,893	21,821	326,709		573,040	899,749
4		TOTAL INTANGIBLE PLANT	1,044,730	115,129	45,943	353,372		634,232	987,604
5									
6		PRODUCTION PLANT							
7		UNADJUSTED PRODUCTION PLANT	26,653,946	1,764,756	769,453	970,075		2,219,460	3,189,536
8		CONTRA ADJ TO EPIS - PROD	-	-	-	-		-	-
9		NON-AFUDC ADJUSTED VALUE	26,653,946	1,764,756	769,453	970,075		2,219,460	3,189,536
10		AFUDC ADJ TO EPIS-PROD	380,829	25,215	10,994	13,860		31,711	45,572
11		TOTAL PRODUCTION PLANT	27,034,775	1,789,971	780,447	983,936		2,251,172	3,235,107
12									
13		TRANSMISSION PLANT							
14	350	350-LAND & LAND RIGHTS	1,194,170	75,003	31,520	1,334		3,124	4,459
15	352	352-STRUCTURES & IMPROVEMENTS	181,513	11,400	4,791	203		475	678
16	352	352-STRUCTURES & IMPROVEMENTS GEN	-	-	-	-		-	-
17	353	353-STATION EQUIPMENT	7,547,536	474,042	199,214	8,432		19,748	28,180
18	353	353-STATION EQUIPMENT GEN	-	-	-	-		-	-
19	354	354-TOWERS & FIXTURES	504,078	31,660	13,305	563		1,319	1,882
20	355	355-POLES & FIXTURES	7,983,782	501,441	210,728	8,919		20,889	29,809
21	356	356-OVERHEAD CONDUCTORS & DEVICES	4,692,809	294,743	123,865	5,243		12,278	17,521
22	357	357-UNDERGROUND CONDUIT	25,520	1,603	674	29		67	95
23	358	358-UNDERGROUND COND & DEVICES	497	31	13	1		1	2
24	359	359- ROADS AND TRAILS	1,459	92	39	2		4	5
25		UNADJUSTED TRANSMISSION PLANT	22,131,364	1,390,015	584,147	24,725		57,906	82,631
26		CONTRA ADJ TO EPIS-TRANS	-	-	-	-		-	-
27		NON-AFUDC ADJUSTED VALUE	22,131,364	1,390,015	584,147	24,725		57,906	82,631
28		AFUDC ADJ TO EPIS - TRANS	9,547	600	252	11		25	36
29		TOTAL TRANSMISSION PLANT	22,140,911	1,390,614	584,399	24,736		57,931	82,666
1		DISTRIBUTION PLANT							
2	360	360-LAND & LAND RIGHTS	33,989	11,668	3,996	11,817		26,310	38,127
3	361	361-STRUCTURES & IMPROVEMENTS	30,913	10,612	3,634	10,748		23,929	34,677

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CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

				MUNICIPAL		LIGHTING			
			TOTAL	PUMPING SERVICE	MUNICIPAL SERVICE	MUNI/PUBLIC LIGHTING	PUBLIC HIGHWAY	PRIVATEAREA LIGHTING	TOTAL
			(25)	(26)	(27)	(28)	(29)	(30)	(31)
4	362	362-STATION EQUIPMENT	993,451	341,046	116,801	345,393		769,020	1,114,413
5	364	364-POLES TOWERS & FIXTURES							
6		PRIMARY	625,800	214,833	73,576	217,572		484,425	701,997
7		SECONDARY	-	182,953	62,658	185,285		412,538	597,823
8		TOTAL ACCOUNT 364		397,786	136,234	402,856		896,963	
9	365	365-OVERHEAD CONDUCTORS & DEVICES							
10		PRIMARY	894,902	307,215	105,215	311,130		692,735	1,003,865
11		SECONDARY	-	123,868	42,422	125,447		279,309	404,756
12		TOTAL ACCOUNT 365		431,083	147,637	436,577		972,044	
13	366	366-UNDERGROUND CONDUIT							
14		PRIMARY	95,717	32,859	11,254	33,278		74,094	107,372
15		SECONDARY	-	43,782	14,995	44,340		98,724	143,064
16		TOTAL ACCOUNT 366		76,641	26,248	77,618		172,818	
17	367	367-UNDERGROUND CONDUCTORS & DEV.							
18		PRIMARY	333,482	114,482	39,208	115,942		258,145	374,087
19		SECONDARY	-	152,538	52,241	154,483		343,957	498,440
20		TOTAL ACCOUNT 367		267,021	91,449	270,424		602,102	
21	368	368-LINE TRANSFORMERS	731,999	251,291	86,062	254,494		566,633	821,127
22	369	369-SERVICES	2,622	87,734	84,413	-		-	-
23	370	370-METERS	90,630	68,336	116,317	-		-	-
24	371	371-INSTALLATIONS	-	-	-	-		8,327,075	8,327,075
25	373	373-STREET LIGHTS	-	-	-	7,510,701		-	7,510,701
26		UNADJUSTED DISTRIBUTION PLANT	3,833,506	1,943,218	812,792	9,320,628		12,356,894	17,846,119
27		CONTRA ADJ TO EPIS- DIST	-	-	-	-		-	-
28		NON-AFUDC ADJUSTED VALUE	3,833,506	1,943,218	812,792	9,320,628		12,356,894	17,846,119
29		AFUDC ADJ TO EPIS - DIST	(6,125)	(3,105)	(1,299)	(14,893)		(19,744)	(34,637)
30		TOTAL DISTRIBUTION PLANT	3,827,381	1,940,113	811,494	9,305,735		12,337,150	21,642,885
		SCHEDULE G-2 ALLOCATION OF RATE BASE							
		ELECTRIC PLANT IN SERVICE							
1		GENERAL PLANT							
2		GENERAL PLANT	3,304,886	208,202	83,571	133,918		307,271	441,189
3		ENERGY	-	-	-	-		-	-
4		TRANSMISSION	-	-	-	-		-	-
5		DISTRIBUTION	-	-	-	-		-	-
6		CAPITAL LEASE ASSETS Net	-	-	-	-		-	-

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

			MUNICIPAL		LIGHTING			
		TOTAL	PUMPING SERVICE	MUNICIPAL SERVICE	MUNI/PUBLIC LIGHTING	PUBLIC HIGHWAY	PRIVATEAREA LIGHTING	TOTAL
		(25)	(26)	(27)	(28)	(29)	(30)	(31)
7	OTHER	-	-	-	-		-	-
8	OTHER	-	-	-	-		-	-
9	UNADJUSTED GENERAL PLANT	3,304,886	208,202	83,571	133,918		307,271	441,189
10	CONTRA ADJ TO EPIS- GENERAL PLT	-	-	-	-		-	-
11	NON-AFUDC ADJUSTED VALUE	3,304,886	208,202	83,571	133,918		307,271	441,189
12	AFUDC ADJ TO EPIS - GENERAL - FUEL RELAT	-	-	-	-		-	-
13	AFUDC ADJ TO EPIS - GENERAL - NON FUEL	-	-	-	-		-	-
14	TOTAL GENERAL PLANT	3,304,886	208,202	83,571	133,918		307,271	441,189
15								
16	TOTAL ELEC PLANT IN SERVICE	57,352,683	5,444,029	2,305,853	10,801,696		15,587,755	26,389,452
	SCHEDULE G-2 ALLOCATION OF RATE BASE							
	ELECTRIC PLANT IN SERVICE							
1	LESS: RESERVE FOR DEPRECIATION							
2	PRODUCTION PLANT	13,363,902	884,823	385,793	486,382		1,112,805	1,599,187
3	CONTRA ADJ TO DEPR - PROD	-	-	-	-		-	-
4	NON-AFUDC ADJUSTED VALUE	13,363,902	884,823	385,793	486,382		1,112,805	1,599,187
5	AFUDC ADJ TO DEPR - PROD	-	-	-	-		-	-
6	TOTAL PROD ACCUM DEPR	13,363,902	884,823	385,793	486,382		1,112,805	1,599,187
7	TRANSMISSION PLANT	5,554,595	348,870	146,611	6,206		14,533	20,739
8	CONTRA ADJ TO DEPR - TRAN	-	-	-	-		-	-
9	NON-AFUDC ADJUSTED VALUE	5,554,595	348,870	146,611	6,206		14,533	20,739
10	AFUDC ADJ TO DEPR - TRAN	-	-	-	-		-	-
11	TOTAL TRAN ACCUM DEPR	5,554,595	348,870	146,611	6,206		14,533	20,739
12	DISTRIBUTION PLANT	1,006,324	510,109	213,364	2,446,733		3,243,776	5,690,509
13	CONTRA ADJ TO DEPR - DIST	-	-	-	-		-	-
14	NON-AFUDC ADJUSTED VALUE	1,006,324	510,109	213,364	2,446,733		3,243,776	5,690,509
15	AFUDC ADJ TO DEPR - DIST	-	-	-	-		-	-
16	TOTAL DIST ACCUM DEPR	1,006,324	510,109	213,364	2,446,733		3,243,776	5,690,509
17	GENERAL PLANT							
18	GENERAL	1,698,029	106,973	42,938	68,806		157,874	226,680
19	GENERAL FUEL	-	-	-	-		-	-
20	TRANSPORTATION	-	-	-	-		-	-
21	RWIP GENERATION	-	-	-	-		-	-
22	RWIP TRANSMISSION	-	-	-	-		-	-
23	RWIP DISTRIBUTION	-	-	-	-		-	-

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

			MUNICIPAL		LIGHTING			
		TOTAL	PUMPING SERVICE	MUNICIPAL SERVICE	MUNI/PUBLIC LIGHTING	PUBLIC HIGHWAY	PRIVATEAREA LIGHTING	TOTAL
		(25)	(26)	(27)	(28)	(29)	(30)	(31)
24	INTANGIBLE	366,369	40,374	16,111	123,921		222,414	346,335
25	TOTAL GENERAL PLANT	2,064,397	147,346	59,049	192,728		380,288	573,015
26	CONTRA ADJ TO DEPR - GENL	-	-	-	-		-	-
27	NON-AFUDC ADJUSTED VALUE	2,064,397	147,346	59,049	192,728		380,288	573,015
28	AFUDC ADJ TO DEPR - GENL	-	-	-	-		-	-
29	TOTAL GENL ACCUM DEPR	2,064,397	147,346	59,049	192,728		380,288	573,015
30	TOT ACCUM PROV FOR DEPR	21,989,219	1,891,149	804,817	3,132,048		4,751,402	7,883,450
31	NET ELECTRIC PLANT IN SERVICE	35,363,464	3,552,881	1,501,036	7,669,648		10,836,353	18,506,001
WORKPAPER E								
	ADDITIONS TO RATE BASE							
1	PLANT HELD FOR FUTURE USE							
2	PRODUCTION	-	-	-	-		-	-
3	TRANSMISSION	-	-	-	-		-	-
4	DISTRIBUTION	-	-	-	-		-	-
5	GENERAL	11,860	747	300	481		1,103	1,583
6	LIGNITE	-	-	-	-		-	-
7	TOTAL PLANT HELD FOR FUTURE USE	11,860	747	300	481		1,103	1,583
8	CONSTRUCTION WORK IN PROGRESS	-						
9	PRODUCTION	-	-	-	-		-	-
10	TRANSMISSION	-	-	-	-		-	-
11	DISTRIBUTION	-	-	-	-		-	-
12	GENERAL							
13	FUEL	-	-	-	-		-	-
14	OTHER	-	-	-	-		-	-
15	TOTAL GENERAL		-	-	-		-	
16	TOTAL CONSTRUCTION WORK IN PROGRESS		-	-	-		-	
17	WORKING CAPITAL							
18	MATERIALS & SUPPLIES							
19	PRODUCTION	238,783	15,810	6,893	8,691		19,883	28,574
20	TRANSMISSION	195,559	12,283	5,162	218		512	730
21	DISTRIBUTION	33,805	17,136	7,167	82,192		108,967	191,160
22	TOT PLANT MAT & SUPP	468,147	45,228	19,222	91,101		129,362	220,464
23	PREPAYMENTS							
24	FAS 87 PENSION	1,116,673	96,307	53,495	272,256		442,106	714,362
25	INSURANCE/MISC/AR FAC	-	-	-	-		-	-

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

			MUNICIPAL		LIGHTING			
		TOTAL	PUMPING SERVICE	MUNICIPAL SERVICE	MUNI/PUBLIC LIGHTING	PUBLIC HIGHWAY	PRIVATEAREA LIGHTING	TOTAL
		(25)	(26)	(27)	(28)	(29)	(30)	(31)
26	FUEL RELATED	-	-	-	-		-	-
27	PLANT	-	-	-	-		-	-
28	TOTAL PREPAYMENTS	1,116,673	96,307	53,495	272,256		442,106	714,362
29	FUEL INVENTORY	809,320	48,530	17,727	35,950		82,668	118,617
30	MISCELLANEOUS WORKING CAP	4,359,113	432,073	183,713	931,323		1,326,287	2,257,610
31	TOTAL WORKING CAPITAL	6,753,253	622,139	274,157	1,330,630		1,980,423	3,311,054
32	PLANT ACQ ADJ NET	-	-	-	-		-	-
33	OTHER ADDITIONS TO RATE BASE							
34	AMAX COAL CONTRACT	-	-	-	-		-	-
35	FUEL LITIGATION DOCKET U23029	-	-	-	-		-	-
36	DEFERRED DSM COSTS DOCKET U23029	-	-	-	-		-	-
37	TRADING DEPOSITS	-	-	-	-		-	-
38	AVAILABLE	-	-	-	-		-	-
39	AVAILABLE	-	-	-	-		-	-
40	AVAILABLE	-	-	-	-		-	-
41	AVAILABLE	-	-	-	-		-	-
42	AVAILABLE	-	-	-	-		-	-
43	TOTAL OTHER ADDITIONS TO RATE BASE	-	-	-	-		-	-
44	TOTAL ADDITIONS-RATE-BASE	6,765,113	622,886	274,457	1,331,111		1,981,526	3,312,637
	SCHEDULE G-2 ALLOCATION OF RATE BASE							
	DEDUCTIONS FROM RATE BASE							
1	ACCUM DEFERRED INCOME TAX							
2	PRODUCTION	-	-	-	-		-	-
3	CONTRA ADJ TO ADIT PROD	-	-	-	-		-	-
4	NON AFUDC ADJ BASIS		-	-	-		-	
5	AFUDC ADJ TO ADIT - PROD	-	-	-	-		-	-
6	TOTAL PROD ADIT		-	-	-		-	
7								
8	TRANSMISSION	-	-	-	-		-	-
9	CONTRA ADJ TO ADIT TRAN	-	-	-	-		-	-
10	NON AFUDC ADJ BASIS		-	-	-		-	
11	AFUDC ADJ TO ADIT - TRAN	-	-	-	-		-	-
12	TOTAL TRAN ADIT		-	-	-		-	
13								

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

			MUNICIPAL		LIGHTING			
		TOTAL	PUMPING SERVICE	MUNICIPAL SERVICE	MUNI/PUBLIC LIGHTING	PUBLIC HIGHWAY	PRIVATEAREA LIGHTING	TOTAL
		(25)	(26)	(27)	(28)	(29)	(30)	(31)
14	DISTRIBUTION	-	-	-	-		-	-
15	CONTRA ADJ TO ADIT DIST	-	-	-	-		-	-
16	NON AFUDC ADJ BASIS		-	-	-		-	
17	AFUDC ADJ TO ADIT - DIST	-	-	-	-		-	-
18	TOTAL DIST ADIT		-	-	-		-	
19								
20	GENERAL	-	-	-	-		-	-
21	CONTRA ADJ TO ADIT GEN	-	-	-	-		-	-
22	NON AFUDC ADJ BASIS		-	-	-		-	
23	AFUDC ADJ TO ADIT - GEN	-	-	-	-		-	-
24	TOTAL GEN ADIT		-	-	-		-	

SOUTHWESTERN ELECTRIC POWER COMPANY
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Schedule: G-2
Cost of Service Study - Rate Base Detail
Class

Explanation: Schedule showing allocation of pro form year functionalized rate base by account, and where applicable by subaccount, at original cost less depreciation and other rate base items to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

			MUNICIPAL		LIGHTING			
		TOTAL	PUMPING SERVICE	MUNICIPAL SERVICE	MUNI/PUBLIC LIGHTING	PUBLIC HIGHWAY	PRIVATEAREA LIGHTING	TOTAL
		(25)	(26)	(27)	(28)	(29)	(30)	(31)
	SCHEDULE G-2 ALLOCATION OF RATE BASE							
	DEDUCTIONS FROM RATE BASE							
1	PLANT RELATED	-	-	-	-		-	-
2	PLANT RELATED	-	-	-	-		-	-
3	PLANT RELATED	-	-	-	-		-	-
4	PLANT RELATED	-	-	-	-		-	-
5	PLANT RELATED	-	-	-	-		-	-
6	PLANT RELATED	-	-	-	-		-	-
7	PLANT RELATED	-	-	-	-		-	-
8	PLANT RELATED	-	-	-	-		-	-
9	PLANT RELATED	-	-	-	-		-	-
10		-	-	-	-		-	-
11	TOTAL ACCUM DEF INC TAX		-	-	-		-	
12								
13	CUSTOMER DEPOSITS	-	-	-	-		-	-
14								
15	PRE-1971 ITC	-	-	-	-		-	-
16								
17	OTHER DEDUCTIONS							
18	MISC DEPOSITS	-	-	-	-		-	-
19	BREMCO LIABILITY	-	-	-	-		-	-
20	POLE ATTACH & MISC PROCEEDS	-	-	-	-		-	-
21	TOTAL OTHER DEDUCTIONS	-	-	-	-		-	-
22								
23	TOTAL DEDUCTIONS-RATE BASE	-	-	-	-		-	-
24								
25	TOTAL RATE BASE	42,128,577	4,175,767	1,775,493	9,000,759		12,817,879	21,818,638

Supporting Schedules
(a) B-1
(b) G-4
(c) F-1.3
WP's G-2
WP's G-2 and G-3
G Class WP

Changes in Allocations

ACCOUNTS/DESCRIPTION	ALLOC	09-008-U	19-008-U	Reason for Change
Class Production Demand	DEMPROD	1 CP & Avg	4CP A& E	1 CP & Avg was determined in Settlement of 09-008-U. SWEPCO supported a class 4CP A&E in 09-008-U. SWEPCO supports a class 4CP A&E in 19-008-U. Please refer to John O Aaron's testimony for more detail. Also changed to comply with Act 725 of 2015.

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supportitng schedules. The associated plant plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner different from the previous rate case and explain the basis for the change.

JURISDICTIONAL

PRODUCTION ALLOCATION METHOD

		TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)	ALLOC
	OPERATING REVENUES				
1	FIRM SALES OF ELECTRICITY				
2	BASE FIRM REVENUE	966,015,521	129,184,908	836,830,612	
3	FIRM FUEL REVENUES	0	0	0	PROPFUEL
4					
5	TOTAL FIRM SALES OF ELECTRICITY	966,015,521	129,184,908	836,830,612	
6					
7	NON-FIRM SALES				
8	NON-FIRM REVENUE-DEMAND	0	0	0	DEMPROD
9	NON-FIRM REVENUE FUEL (Capacity Revenue)	0	0	0	DEMPROD
10	TOTAL NON-FIRM SALES	0	0	0	
11					
12	450-FORFEITED DISCOUNTS	5,032,195	1,336,725	3,695,470	CUSTRET
13					
14	451-MISCELLANEOUS SERVICE REVENUE	2,250,904	597,918	1,652,986	CUSTRET
15					
16	454 - RENT FROM ELECTRIC PROPERTY	9,561,976	1,901,677	7,660,299	DISTPLT
17					
18	456 - OTHER ELECTRIC REVENUES				
19	GENERATION RELATED	4,385,253	852,590	3,532,663	DEMPROD
20	GENERAL OFFICE RENTAL	1,511,766	305,087	1,206,678	GENPLT
21	TRANS RELATED REVENUE	111,607,666	22,753,982	88,853,684	TRANPLT
22	TOTAL OTHER ELECTRIC REVENUES	117,504,685	23,911,659	93,593,026	
23					
24	TOTAL OTHER OPERATING REVENUE	134,349,761	27,747,979	106,601,782	
25					
26	TOTAL OPERATING REVENUES	1,100,365,282	156,932,888	943,432,394	
	OPERATION & MAINTENANCE EXPENSE				
1	POWER PRODUCTION EXPENSES				
2	STEAM POWER GENERATION				
3	OPERATION				
4	500-SUPERVISION & ENGINEERI NG	18,059,735	3,445,742	14,613,993	LAB501_507

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supportitng schedules. The associated plant plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner different from the previous rate case and explain the basis for the change.

JURISDICTIONAL

PRODUCTION ALLOCATION METHOD

		TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)	ALLOC
5	501-FUEL				
6	DIRECT ASSIGNED COMMODITY FUEL	0	0	0	ENERGY
7	DIRECT ASSIGNED OFF SYSTEM WSALE	0	0	0	PROPFUEL
8	DIRECT ASSIGNED RETAIL NFIRM	0	0	0	PROPFUEL
9	NON-ELIGIBLE	19,388,616	3,413,437	15,975,179	ENERGY
10	MINE CLOSING	0	0	0	MINECLOSE
11	AVAILABLE	0	0	0	MINECLOSE
12	TOTAL ACCOUNT 501	19,388,616	3,413,437	15,975,179	
13	502-STEAM	15,586,826	3,030,422	12,556,404	PRODPLT
14	505-ELECTRIC	6,094,085	1,184,824	4,909,261	PRODPLT
15	506-MISCELLANEOUS POWER	20,741,309	4,032,566	16,708,743	PRODPLT
16	507-RENTS	1,869	363	1,506	PRODPLT
17	509-ALLOWANCE EXPENSE	257,261	50,017	207,244	PRODPLT
18	TOTAL STEAM OPERATION	80,129,701	15,157,372	64,972,329	
19	MAINTENANCE				
20	510-SUPERVISION & ENGINEERING	5,273,141	937,255	4,335,886	LAB511_514
21	511-STRUCTURES	2,837,655	551,702	2,285,953	PRODPLT
22	512-BOILER PLANT	45,774,504	8,058,769	37,715,735	ENERGY
23	513-ELECTRIC PLANT	5,579,530	982,297	4,597,233	ENERGY
24	514-MISC STEAM PLANT	4,106,074	798,311	3,307,763	PRODPLT
25	TOTAL STEAM MAINTENANCE	63,570,904	11,328,335	52,242,569	
26	TOTAL STEAM GENERATION EXPENSE	143,700,605	26,485,707	117,214,898	
27	POWER PRODUCTION EXPENSES-OTHER				
28	OPERATION				LAB547_550
29	546-OPERATION & SUPERVISION	0	0	0	prodplt
30	547-FUEL	0	0	0	ENERGY
31	548-GEN EXP	635,668	123,588	512,080	PRODPLT
32	549-MISCELLANEOUS OTHER POWER GEN	0	0	0	PRODPLT
33	550-RENTS	0	0	0	PRODPLT
34	TOTAL OTHER POWER OPERATION	635,668	123,588	512,080	
35	MAINTENANCE				
36	551-SUPERVISION & ENGINEERING	0	0	0	LAB552_554
37	552-STRUCTURES	0	0	0	PRODPLT
38	553-GENERAL & ELECTRIC PLANT	633,906	123,245	510,661	PRODPLT
39	554-MISCELLANEOUS OTHER GEN	16,954	3,296	13,658	PRODPLT
40	TOTAL OTHER POWER MAINTENANCE	650,860	126,541	524,319	
41	TOTAL OTHER POWER	1,286,528	250,129	1,036,399	

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supportitng schedules. The associated plant plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner different from the previous rate case and explain the basis for the change.

JURISDICTIONAL

PRODUCTION ALLOCATION METHOD

		TOTAL COMPANY	AT ISSUE ARKANSAS RETAIL	ALL OTHER	ALLOC
		(1)	(2)	(3)	
42	OTHER GENERATION EXPENSES				
43	555-PURCHASED POWER DEMAND	9,049,483	1,759,418	7,290,065	DEMPROD
44	555-PURCHASED POWER ENERGY	0	0	0	ENERGY
45	555-PURCHASED POWER FUEL	0	0	0	ENERGY
46	TOTAL ACCOUNT 555	9,049,483	1,759,418	7,290,065	
47	556-SYSTEM DISPATCHING	1,922,357	373,748	1,548,609	PRODPLT
48	557-Fuel Related	0	0	0	FUELADJ
49	557-OTHER	3,693,825	718,161	2,975,664	PRODPLT
50	TOTAL OTHER PRODUCTION EXPENSE	14,665,665	2,851,328	11,814,337	
51	TOTAL PRODUCTION O&M EXPENSE	159,652,798	29,587,164	130,065,634	
52					
53					
1	TRANSMISSION EXPENSES				
2	OPERATION				
3	560-SUPERVISION & ENGR	7,445,340	1,517,917	5,927,423	LAB561_567
4	561-LOAD DISPATCHING	14,366,768	2,929,021	11,437,747	TRANPLT
5	562-STATION EQUIPMENT	538,307	109,747	428,560	TRANSUB
6	563-OVERHEAD LINES	424,831	86,612	338,219	TRANOHLN
7	564-UNDERGROUND LINES	0	0	0	TRANUGLN
8	565-TRANSMISSION FOR OTHERS	0	0	0	
9	OATT AFFILIATED	0	0	0	TRANPLT
10	SPP FEES	105,886,115	21,587,502	84,298,613	SPPDEMAND
11	3RD PARTY WHEELING	0	0	0	ENERGY
12	TOTAL TRANSMISSION BY OTHERS	105,886,115	21,587,502	84,298,613	
13	566-MISC TRANSMISSION	1,960,018	399,598	1,560,420	TRANPLT
14	566-MISC TRANSMISSION SPP	0	0	0	SPPDEMAND
15	567-RENTS	36,806	7,504	29,302	TRANPLT
16	5757-SPP Admin-MAM&SC	1,514,936	308,857	1,206,079	SPPDEMAND
17	TOTAL TRANSMISSION OPERATION	132,173,121	26,946,758	105,226,363	
18					
19	MAINTENANCE				
20	568-SUPERVISION & ENGR	41,207	8,401	32,806	LAB569_573
21	569-STRUCTURES	574,157	117,056	457,101	TRANSUB
22	570-STATION EQUIPMENT	3,525,596	718,780	2,806,816	TRANSUB
23	571-OVERHEAD LINES	10,344,498	2,108,982	8,235,516	TRANOHLN
24	571-OVERHEAD LINES	0	0	0	Direct Assigned

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JURISDICTIONAL

PRODUCTION ALLOCATION METHOD

		TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)	ALLOC
25	572-UNDERGROUND LINES	952	194	758	TRANUGLN
26	573-MISCELLANEOUS	38,473	7,844	30,629	TRANPLT
27	TOTAL TRANSMISSION MAINTENANCE	14,524,883	2,961,257	11,563,626	
28					
29	TOTAL TRANSMISSION O&M EXP	146,698,004	29,908,015	116,789,989	

OPERATION & MAINTENANCE EXPENSE

		TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)	ALLOC
1	DISTRIBUTION EXPENSES				
2	OPERATION				
3	580-SUPERVISION & ENGR	2,383,634	482,490	1,901,144	LAB581_589
4	581-LOAD DISPATCHING	31,527	6,270	25,257	DISTPLT
5	582-STATION EQUIPMENT	426,419	103,510	322,909	PLT362
6	583-OVERHEAD LINES	3,104,881	602,750	2,502,131	DISTOHLN
7	584-UNDERGROUND LINES	2,128,460	508,483	1,619,977	DISTUGLN
8	585-STREET LIGHTING & SIGNAL	201,658	33,345	168,313	PLT373
9	586-METERS	3,447,028	698,380	2,748,648	PLT370
10	587-CUST INSTALLATION	717,753	126,372	591,381	PLT371
11	588-MISC DISTRIBUTION	19,180,121	3,814,525	15,365,596	DISTPLT
12	589-RENTS	891,782	177,357	714,425	DISTPLT
13	TOTAL DISTRIBUTION OPERATION	32,513,263	6,553,482	25,959,781	
14					
15	MAINTENANCE				
16	590-SUPERVISION & ENGR	368,237	72,853	295,384	LAB591_598
17	591-STRUCTURES	22,464	6,709	15,755	PLT361
18	592-STATION EQUIPMENT	680,258	165,128	515,130	PLT362
19	593-OVERHEAD LINES	24,759,034	4,806,467	19,952,567	DISTOHLN
20	593-OVERHEAD LINES	26,000,391	3,208,866	22,791,525	Direct Assigned
21	594-UNDERGROUND LINES	1,014,404	242,338	772,066	DISTUGLN
22	595-LINE TRANSFORMERS	138,531	19,704	118,827	PLT368
23	596-STREET LIGHTING & SIGNAL	389,545	64,412	325,133	PLT373
24	597-METERS	474,232	96,081	378,151	PLT370
25	598-MISCELLANEOUS PLANT	244,347	43,021	201,326	PLT371
26	TOTAL DISTRIBUTION MAINTENANCE	54,091,443	8,725,579	45,365,864	
27					
28	TOTAL DISTRIBUTION EXPENSES	86,604,706	15,279,061	71,325,645	

SOUTHWESTERN ELECTRIC POWER COMPANY
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TEST YEAR ENDING DECEMBER 31, 2018

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JURISDICTIONAL

PRODUCTION ALLOCATION METHOD

		TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)	ALLOC
	OPERATION & MAINTENANCE EXPENSE				
1	CUSTOMER ACCOUNTS EXPENSES				
2	OPERATION				
3	901-SUPERVISION & ENGR	680,545	162,910	517,635	LAB902_905
4	902-METER READING	2,149,818	480,793	1,669,025	CUST902
5	903-CUST ACCT & COLL-GENL	0	0	0	CUSER5
6	CUST ACCT & COLL-BILLING	16,781,707	4,065,728	12,715,979	CUST903
7	FACTORING EXP	0	0	0	REVSALES
8	INTEREST ON CUSTOMER DEPOSITS	0	0	0	CUSTDEPA
9	TOTAL 903	16,781,707	4,065,728	12,715,979	
10	904-UNCOLLECTABLE	2,608,677	348,857	2,259,820	REVSALES
11	905-MISCELLANEOUS	105,705	25,304	80,401	LAB902_903
12	TOT CUSTOMER ACCOUNTS	22,326,452	5,083,592	17,242,860	
13					
14	CUSTOMER INFORMATION				
15	OPERATION				
16	907-SUPERVISION	694,860	218,846	476,014	LAB908_910
17	908-CUSTOMER ASSISTANCE				
18	CUSTOMER ASSISTANCE	2,407,814	758,779	1,649,035	CUSER7
19	ENERY EFFIC INCENTIVE AMORT	0	0	0	CUSER7
20	TOTAL ACCOUNT 908	2,407,814	758,779	1,649,035	
21	909-INFO & INSTRUCTION	14,453	3,146	11,307	CUSER7
22	910-MISC CUSTOMER SERVICE	8,545	1,860	6,685	CUSER7
23	TOT CUSTOMER INFO	3,125,672	982,631	2,143,041	
24					
25	CONSUMER SERVICES				
26	OPERATION				
27	911-SUPERVISION	321	70	251	CUSER7
28	912-DEMO & SELLING	166,320	36,201	130,119	CUSER7
29	913-ADVERTISING	(22,410)	(4,878)	(17,532)	CUSER7
30	916-MISC SALES EXP	0	0	0	CUSER7
31	TOT CONSUMER SVCS	144,231	31,393	112,838	
32					
33	ADMINISTRATIVE & GENERAL EXP				

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Schedule: G-3
Cost of Service Study - Revenue and Expense Detail
Jurisdiction

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporitng schedules. The associated plant plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner different from the previous rate case and explain the basis for the change.

JURISDICTIONAL

PRODUCTION ALLOCATION METHOD

		TOTAL COMPANY	AT ISSUE ARKANSAS RETAIL	ALL OTHER	ALLOC
		(1)	(2)	(3)	
34	920-ADMINISTRATIVE AND GENERAL	34,324,100	6,926,902	27,397,198	LABORT
35	921-OFFICE SUPPLIES AND EXPNESES	2,499,100	504,340	1,994,760	LABORT
36	922-ADMIN EXPENSE TRANSFERRED	(3,684,920)	(743,649)	(2,941,271)	LABORT
37	923-OUTSIDE SERVICES	17,643,733	3,560,659	14,083,074	LABORT
38	924-PROPERTY INSURANCE	2,123,085	421,288	1,701,797	PLANT
39	925-INJURIES AND DAMAGES	4,317,506	871,310	3,446,196	LABORT
40	926-EMPLOYEE PENSION AND BENEFITS	9,989,597	2,015,988	7,973,609	LABORT
41	928-REGULATORY COMMISSION EXPENSE - Ark	0	0	0	REVSALEAR
42	928-REGULATORY COMMISSION EXPENSE - La	0	0	0	REVSALELA
43	928-REGULATORY COMMISSION EXPENSE - Tx	0	0	0	REVSALETX
44	928-REGULATORY COMMISSION EXPENSE - FERC	3,180,243	0	3,180,243	REVSALESW
45	928-REGULATORY COMMISSION EXPENSE	0	0	0	LABORT
46	9301-GENERAL ADVERTISING EXPENSE	264,916	58,078	206,838	LABORXR
47	9302-MISCELLANEOUS GENERAL EXPENSE	1,679,105	338,858	1,340,247	LABORT
48	931-RENTS	896,505	180,923	715,582	GENPLT
49	935-MAINTENANCE OF GENERAL PLANT	6,269,841	1,265,309	5,004,532	GENPLT
50		0	0	0	LABORT
51	TOT ADMIN & GEN EXP	79,502,811	15,400,005	64,102,806	
52					
53	TOTAL OPERATION & MAINT EXP	498,054,674	96,271,860	401,782,814	

1	DEPRECIATION EXPENSE - ACCT 403				
2	PRODUCTION PLANT	92,267,658	17,938,861	74,328,797	PRODPLT
3	TRANSMISSION PLANT	46,953,026	9,572,535	37,380,491	TRANPLT
4	DISTRIBUTION PLANT	69,502,443	13,822,581	55,679,862	DISTPLT
5	GENERAL PLANT	5,143,726	1,038,049	4,105,677	GENPLT
6	SUBTOTAL DEPRECIATION EXPENSE	213,866,853	42,372,026	171,494,827	
7					
8	AMORTIZATION EXPENSE				
9	404-INTANGIBLE PLANT	19,977,813	4,031,697	15,946,116	LABORT
10	406-PLANT ACQ ADJUSTMENT	0	0	0	DISTPLTLA
11	4073-Amortization Exp Ark	542,500	542,500	0	REVSALEAR
12	4073-Amortization Exp La	417,016	0	417,016	REVSALELA
13	4073-Amortization Exp Tx	(72,000)	0	(72,000)	REVSALETX
14	4073-Amortization Exp Tx	0	0	0	PRODPLTR

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JURISDICTIONAL

PRODUCTION ALLOCATION METHOD

		TOTAL COMPANY	AT ISSUE ARKANSAS RETAIL	ALL OTHER	ALLOC
		(1)	(2)	(3)	
15	Accretion	2,558,193	506,838	2,051,355	DEPEXP
16	SUBTOTAL AMORTIZATION	23,423,522	5,081,035	18,342,487	
17					
18	TOTAL DEPRECIATION & AMORT EXP	237,290,374	47,453,060	189,837,314	
19					
20	SO2 ALLOWANCE	619,127	120,372	498,755	PRODPLT
21					
22	TAXES OTHER THAN INCOME TAX				
23	NON REVENUE RELATED TAXES				
24					
25	PAYROLL RELATED TAXES	7,611,185	1,536,003	6,075,182	LABORT
26	PLANT RELATED TAXES	62,321,326	12,366,538	49,954,788	PLANT
27	STATE FRANCHISE (DEL, NE, OK)	32,570	6,474	26,096	RBX
28					
29	TOTAL NON-REV RELATED TAX	69,965,081	13,909,015	56,056,066	
1	REVENUE RELATED TAXES				
2	REVENUE RELATED TAXES ARK	575,313	575,313	0	RVSALEARR
3	REVENUE RELATED TAXES LA	23,747,973	0	23,747,973	RVSALELAR
4	REVENUE RELATED TAXES TX	6,950,053	0	6,950,053	RVSALETXR
5					
6	TOTAL REVENUE-RELATED TAX	31,273,339	575,313	30,698,026	
7					
8	TOT TAX OTHER THAN INCOME	101,238,420	14,484,328	86,754,092	
	FEDERAL INCOME TAX CALCULATION - PRESENT				
1	TOTAL REVENUES	1,100,365,282	156,932,888	943,432,394	
2	LESS: EXPENSES				
3	TOTAL OPER & MAINT EXPENSE	498,673,801	96,392,232	402,281,569	
4	TOTAL DEPRECIATION EXPENSE	237,290,374	47,453,060	189,837,314	
5	TOT TAX OTHER THAN INCOME	101,238,420	14,484,328	86,754,092	
6	TOTAL EXPENSES	837,202,595	158,329,621	678,872,975	
7	OPERATING INCOME BEFORE TAXES	263,162,686	(1,396,733)	264,559,419	
8					

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Schedule: G-3
Cost of Service Study - Revenue and Expense Detail
Jurisdiction

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporitng schedules. The associated plant plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner different from the previous rate case and explain the basis for the change.

JURISDICTIONAL

PRODUCTION ALLOCATION METHOD

		TOTAL COMPANY	AT ISSUE ARKANSAS RETAIL	ALL OTHER	ALLOC
		(1)	(2)	(3)	
9	LESS: INTEREST	95,611,659	19,004,497	76,607,162	RBX
10					
11	PLUS: SCHEDULE M DIFFERENCES				
12	PERMANENT				
13	DEPRECIATION EXP RELATED	6,081,905	1,204,968	4,876,937	DEPREXP
14	ENERGY RELATED	(15,600,000)	(2,746,437)	(12,853,563)	ENERGY
15	TOTAL PAYROLL RELATED	423,600	85,486	338,114	LABORT
16	PLANT RELATED	0	0	0	PLANT
17	INTANGIBLE PLANT RELATED	0	0	0	INTPLT
18	TEMPORARY				
19	RETAIL CUSTOMER RELATED	0	0	0	CUSTINFO
20	RETAIL PROD DEMAND RELATED	0	0	0	DEMRTAIL
21	DEPRECIATION EXP RELATED	(21,626,720)	(4,284,759)	(17,341,961)	DEPREXP
22	DISTRIBUTION PLANT RELATED	2,384,038	474,135	1,909,903	DISTPLT
23	ENERGY RELATED	(5,392,003)	(949,282)	(4,442,721)	ENERGY
24	FUEL RELATED	0	0	0	FUEL
25	INTANGIBLE PLANT RELATED	0	0	0	INTPLT
26	TOTAL PAYROLL RELATED	(2,619,066)	(528,550)	(2,090,516)	LABORT
27	MINE RECLAMATION	0	0	0	MINECLOSE
28	PLANT RELATED	(28,801,512)	(5,715,138)	(23,086,374)	PLANT
29	RATE BASE RELATED	(123,675)	(24,583)	(99,092)	RBX
30	AVAILABLE				AVAIL
31	AVAILABLE	0	0	0	AVAIL
32	TOTAL DEDUCTIONS	(65,273,433)	(12,484,160)	(52,789,273)	
33					
34	ADJUSTED INCOME	102,277,594	(32,885,391)	135,162,985	
35					
36	LESS:				
37	SIT DEDUCTION	3,133,910	(1,040,062)	4,173,972	
38	SIT DEDUCTION	0	0	0	
39	SIT DEDUCTION	0	0	0	
40					
41	FEDERAL TAXABLE INCOME	99,143,684	(31,845,328)	130,989,012	
42					
43	TAX AT PRESENT BEFORE CREDITS	20,820,174	(6,687,519)	27,507,693	
44					
45	AFTER TAX PROVISIONS				

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JURISDICTIONAL

PRODUCTION ALLOCATION METHOD

		TOTAL COMPANY	AT ISSUE ARKANSAS RETAIL	ALL OTHER	ALLOC
		(1)	(2)	(3)	
46	CURRENT SIT	3,133,910	(1,040,062)	4,173,972	
47	DEFERRED SIT	2,067,385	(686,111)	2,753,496	SIT
48	DEFERRED FIT	11,797,577	2,315,917	9,481,660	FITTEMP
49	DEFERRED - EXCESS PROTECTED	(26,980,757)	(1,916,163)	(25,064,594)	
50	ITC	(386,757)	(76,745)	(310,012)	PLANT
51					
52	INCOME TAXES CHARGED TO UTILITY	10,451,532	(8,090,683)	18,542,214	

LOUISIANA INCOME TAX CALCULATION

		TOTAL COMPANY	AT ISSUE ARKANSAS RETAIL	ALL OTHER	ALLOC
1	NET INCOME FROM LOUISIANA SOURCES	102,277,594	0	102,277,594	TAXINCLA
2	Deductible State Tax Expense (States other than LA)	(1,007,195)	0	(1,007,195)	PLANTLA
3	INC SUBJECT TO APPORTIONMENT	101,270,399	0	101,270,399	
4	INC APPORTIONED AT 0.243859	24,695,698	0	24,695,698	0.243859000
5	RENTS/ROYALTIES - LA ONLY	0	0	0	PLANTLA
6	LA FEDERAL INC TAX DED	0	0	0	PLANTLA
7	LOUISIANA TAXABLE INCOME	24,695,698	0	24,695,698	
8	LA TAXES CHARGED TO UTILITY	1,605,220	0	1,605,220	0.06500000

ARKANSAS INCOME TAX CALCULATION

		TOTAL COMPANY	AT ISSUE ARKANSAS RETAIL	ALL OTHER	ALLOC
1	FEDERAL TAXABLE INCOME	102,277,594	102,277,594	0	TAXINCAR
2					
3	PLUS:				
4	Deductible State Tax Expense (States other than AR)	(2,254,141)	(2,254,141)	0	PLANTAR
5	BONUS DEPRECIATION	(149,025,000)	(149,025,000)	0	TAXINCAR
6	1999 CAPITAL LOSSES / GAINS	0	0	0	PLANTAR
7					
8	INC SUBJECT TO APPORTIONMENT	(49,001,547)	(49,001,547)	0	
9					
10	INC APPORTIONED AT 0.243859	(11,949,468)	(11,949,468)	0	0.243859
11	AR TAXES CHARGED TO UTILITY	(776,715)	(776,715)	0	0.0650000
12					
13	TEXAS GROSS RECEIPTS TAX	1,511,890	0	1,511,890	DIRECT
14	OTHER STATE INCOME TAX	793,515	(263,347)	1,056,862	STATETAXCALC

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JURISDICTIONAL

PRODUCTION ALLOCATION METHOD

		TOTAL COMPANY	AT ISSUE ARKANSAS RETAIL	ALL OTHER	ALLOC
		(1)	(2)	(3)	
15					
16	TOTAL STATE INCOME TAXES	3,133,910	(1,040,062)	4,173,972	

Supporting Schedules
(a) C-1
(b) G-4
(c) H-1
(d) F-1.3
WP's G-2
WP's G-2 and G-3
G Juris WP

Recap Schedules
(A) G-1

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CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TOTAL AR RETAIL JURISDICTION (1)	RESIDENTIAL (2)	COMMERCIAL / SMALL INDUSTRIAL (3)	LARGE INDUSTRIAL (4)	MUNICIPAL (5)	LIGHTING (6)
	OPERATING REVENUES						
1	FIRM SALES OF ELECTRICITY						
2	BASE FIRM REVENUE	129,184,908	53,645,062	59,079,104	11,148,764	753,656	4,558,322
3	FIRM FUEL REVENUES	0	0	0	0	0	0
4							
5	TOTAL FIRM SALES OF ELECTRICITY	129,184,908	53,645,062	59,079,104	11,148,764	753,656	4,558,322
6							
7	NON-FIRM SALES						
8	NON-FIRM REVENUE-DEMAND	0	0	0	0	0	0
9	NON-FIRM REVENUE FUEL (Capacity Revenue)	0	0	0	0	0	0
10	TOTAL NON-FIRM SALES	0	0	0	0	0	0
11							
12	450-FORFEITED DISCOUNTS	1,336,725	900,037	157,645	80	6,686	272,277
13							
14	451-MISCELLANEOUS SERVICE REVENUE	597,918	402,587	70,515	36	2,991	121,790
15							
16	454 - RENT FROM ELECTRIC PROPERTY	1,901,677	872,050	860,495	68,387	11,364	89,382
17							
18	456 - OTHER ELECTRIC REVENUES						
19	GENERATION RELATED	852,590	343,821	410,439	90,205	3,597	4,527
20	GENERAL OFFICE RENTAL	305,087	110,476	152,988	37,965	1,456	2,202
21	TRANS RELATED REVENUE	22,753,982	8,819,750	11,036,572	2,783,854	109,233	4,572
22	TOTAL OTHER ELECTRIC REVENUES	23,911,659	9,274,047	11,599,999	2,912,025	114,287	11,301

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CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TOTAL AR RETAIL JURISDICTION (1)	RESIDENTIAL (2)	COMMERCIAL / SMALL INDUSTRIAL (3)	LARGE INDUSTRIAL (4)	MUNICIPAL (5)	LIGHTING (6)
23							
24	TOTAL OTHER OPERATING REVENUE	27,747,979	11,448,721	12,688,654	2,980,527	135,328	494,750
25							
26	TOTAL OPERATING REVENUES	156,932,888	65,093,783	71,767,758	14,129,291	888,984	5,053,071
	OPERATION & MAINTENANCE EXPENSE						
1	POWER PRODUCTION EXPENSES						
2	STEAM POWER GENERATION						
3	OPERATION						
4	500-SUPERVISION & ENGINEERI NG	3,445,742	1,326,272	1,689,626	393,224	15,390	21,230
5	501-FUEL						
6	DIRECT ASSIGNED COMMODITY FUEL	-	-	-	-	-	-
7	DIRECT ASSIGNED OFF SYSTEM WSALE	-	-	-	-	-	-
8	DIRECT ASSIGNED RETAIL NFIRM	-	-	-	-	-	-
9	NON-ELIGIBLE	3,413,437	1,032,273	1,810,980	517,065	19,037	34,082
10	MINE CLOSING	-	-	-	-	-	-
11	AVAILABLE	-	-	-	-	-	-
12	TOTAL ACCOUNT 501	3,413,437	1,032,273	1,810,980	517,065	19,037	34,082
13	502-STEAM	3,030,422	1,222,070	1,458,854	320,621	12,785	16,092
14	505-ELECTRIC	1,184,824	477,801	570,378	125,355	4,999	6,291
15	506-MISCELLANEOUS POWER	4,032,566	1,626,202	1,941,290	426,649	17,013	21,413
16	507-RENTS	363	147	175	38	2	2
17	509-ALLOWANCE EXPENSE	50,017	20,170	24,078	5,292	211	266

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CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TOTAL AR RETAIL JURISDICTION	RESIDENTIAL	COMMERCIAL / SMALL INDUSTRIAL	LARGE INDUSTRIAL	MUNICIPAL	LIGHTING
		(1)	(2)	(3)	(4)	(5)	(6)
18	TOTAL STEAM OPERATION	15,157,372	5,704,934	7,495,380	1,788,245	69,437	99,375
19	MAINTENANCE						
20	510-SUPERVISION & ENGINEERING	937,255	292,940	492,626	137,672	5,099	8,918
21	511-STRUCTURES	551,702	222,484	265,591	58,371	2,328	2,930
22	512-BOILER PLANT	8,058,769	2,437,090	4,275,534	1,220,736	44,945	80,464
23	513-ELECTRIC PLANT	982,297	297,061	521,152	148,798	5,478	9,808
24	514-MISC STEAM PLANT	798,311	321,933	384,309	84,462	3,368	4,239
25	TOTAL STEAM MAINTENANCE	11,328,335	3,571,507	5,939,213	1,650,038	61,219	106,358
26	TOTAL STEAM GENERATION EXPENSE	26,485,707	9,276,441	13,434,594	3,438,283	130,656	205,733
27	POWER PRODUCTION EXPENSES-OTHER						
28	OPERATION	-	-	-	-	-	-
29	546-OPERATION & SUPERVISION	-	-	-	-	-	-
30	547-FUEL	-	-	-	-	-	-
31	548-GEN EXP	123,588	49,839	59,496	13,076	521	656
32	549-MISCELLANEOUS OTHER POWER GEN	-	-	-	-	-	-
33	550-RENTS	-	-	-	-	-	-
34	TOTAL OTHER POWER OPERATION	123,588	49,839	59,496	13,076	521	656
35	MAINTENANCE						
36	551-SUPERVISION & ENGINEERING	-	-	-	-	-	-
37	552-STRUCTURES	-	-	-	-	-	-
38	553-GENERAL & ELECTRIC PLANT	123,245	49,701	59,331	13,039	520	654
39	554-MISCELLANEOUS OTHER GEN	3,296	1,329	1,587	349	14	18
40	TOTAL OTHER POWER MAINTENANCE	126,541	51,030	60,917	13,388	534	672
41	TOTAL OTHER POWER	250,129	100,869	120,413	26,464	1,055	1,328

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CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TOTAL AR RETAIL JURISDICTION (1)	RESIDENTIAL (2)	COMMERCIAL / SMALL INDUSTRIAL (3)	LARGE INDUSTRIAL (4)	MUNICIPAL (5)	LIGHTING (6)
42	OTHER GENERATION EXPENSES						
43	555-PURCHASED POWER DEMAND	1,759,418	709,516	846,989	186,148	7,423	9,342
44	555-PURCHASED POWER ENERGY	-	-	-	-	-	-
45	555-PURCHASED POWER FUEL	-	-	-	-	-	-
46	TOTAL ACCOUNT 555	1,759,418	709,516	846,989	186,148	7,423	9,342
47	556-SYSTEM DISPATCHING	373,748	150,720	179,924	39,543	1,577	1,985
48	557-Fuel Related	-	-	-	-	-	-
49	557-OTHER	718,161	289,611	345,725	75,982	3,030	3,813
50	TOTAL OTHER PRODUCTION EXPENSE	2,851,328	1,149,847	1,372,638	301,673	12,030	15,141
51	TOTAL PRODUCTION O&M EXPENSE	29,587,164	10,527,157	14,927,644	3,766,419	143,741	222,202
	OPERATION & MAINTENANCE EXPENSE						
1	TRANSMISSION EXPENSES						
2	OPERATION						
3	560-SUPERVISION & ENGR	1,517,917	588,365	736,249	185,711	7,287	305
4	561-LOAD DISPATCHING	2,929,021	1,135,328	1,420,690	358,353	14,061	589
5	562-STATION EQUIPMENT	109,747	42,539	53,232	13,427	527	22
6	563-OVERHEAD LINES	86,612	33,572	42,010	10,597	416	17
7	564-UNDERGROUND LINES	-	-	-	-	-	-
8	565-TRANSMISSION FOR OTHERS	-	-	-	-	-	-
9	OATT AFFILIATED	-	-	-	-	-	-
10	SPP FEES	21,587,502	8,367,607	10,470,783	2,641,141	103,634	4,338
11	3RD PARTY WHEELING	-	-	-	-	-	-

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TOTAL AR RETAIL JURISDICTION (1)	RESIDENTIAL (2)	COMMERCIAL / SMALL INDUSTRIAL (3)	LARGE INDUSTRIAL (4)	MUNICIPAL (5)	LIGHTING (6)
12	TOTAL TRANSMISSION BY OTHERS	21,587,502	8,367,607	10,470,783	2,641,141	103,634	4,338
13	566-MISC TRANSMISSION	399,598	154,890	193,821	48,889	1,918	80
14	566-MISC TRANSMISSION SPP	-	-	-	-	-	-
15	567-RENTS	7,504	2,909	3,640	918	36	2
16	5757-SPP Admin-MAM&SC	308,857	119,717	149,808	37,787	1,483	62
17	TOTAL TRANSMISSION OPERATION	26,946,758	10,444,927	13,070,232	3,296,823	129,361	5,415
18							
19	MAINTENANCE						
20	568-SUPERVISION & ENGR	8,401	3,256	4,075	1,028	40	2
21	569-STRUCTURES	117,056	45,373	56,777	14,321	562	24
22	570-STATION EQUIPMENT	718,780	278,609	348,636	87,940	3,451	144
23	571-OVERHEAD LINES	2,108,982	817,470	1,022,939	258,025	10,124	424
24	571-OVERHEAD LINES	-	-	-	-	-	-
25	572-UNDERGROUND LINES	194	75	94	24	1	0
26	573-MISCELLANEOUS	7,844	3,040	3,804	960	38	2
27	TOTAL TRANSMISSION MAINTENANCE	2,961,257	1,147,823	1,436,325	362,297	14,216	595
28							
29	TOTAL TRANSMISSION O&M EXP	29,908,015	11,592,750	14,506,558	3,659,120	143,577	6,010

OPERATION & MAINTENANCE EXPENSE

1 DISTRIBUTION EXPENSES
2 OPERATION

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TOTAL AR RETAIL JURISDICTION	RESIDENTIAL	COMMERCIAL / SMALL INDUSTRIAL	LARGE INDUSTRIAL	MUNICIPAL	LIGHTING
		(1)	(2)	(3)	(4)	(5)	(6)
3	580-SUPERVISION & ENGR	482,490	232,188	204,185	14,150	3,143	28,824
4	581-LOAD DISPATCHING	6,270	2,875	2,837	225	37	295
5	582-STATION EQUIPMENT	103,510	44,278	51,643	5,579	585	1,425
6	583-OVERHEAD LINES	602,750	274,115	294,438	21,751	3,624	8,821
7	584-UNDERGROUND LINES	508,483	239,458	245,218	12,935	3,166	7,706
8	585-STREET LIGHTING & SIGNAL	33,345	-	-	-	-	33,345
9	586-METERS	698,380	462,990	222,550	5,886	6,954	-
10	587-CUST INSTALLATION	126,372	-	-	-	-	126,372
11	588-MISC DISTRIBUTION	3,814,525	1,749,222	1,726,044	137,175	22,794	179,289
12	589-RENTS	177,357	81,330	80,253	6,378	1,060	8,336
13	TOTAL DISTRIBUTION OPERATION	6,553,482	3,086,457	2,827,168	204,079	41,364	394,413
14							
15	MAINTENANCE						
16	590-SUPERVISION & ENGR	72,853	32,411	33,395	2,415	433	4,199
17	591-STRUCTURES	6,709	2,870	3,347	362	38	92
18	592-STATION EQUIPMENT	165,128	70,636	82,386	8,899	934	2,273
19	593-OVERHEAD LINES	4,806,467	2,185,856	2,347,915	173,451	28,901	70,345
20	593-OVERHEAD LINES	3,208,866	1,471,486	1,451,988	115,395	19,175	150,822
21	594-UNDERGROUND LINES	242,338	114,124	116,869	6,165	1,509	3,673
22	595-LINE TRANSFORMERS	19,704	8,429	9,831	1,062	111	271
23	596-STREET LIGHTING & SIGNAL	64,412	-	-	-	-	64,412
24	597-METERS	96,081	63,697	30,618	810	957	-
25	598-MISCELLANEOUS PLANT	43,021	-	-	-	-	43,021
26	TOTAL DISTRIBUTION MAINTENANCE	8,725,579	3,949,507	4,076,348	308,558	52,057	339,109

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TOTAL AR RETAIL JURISDICTION (1)	RESIDENTIAL (2)	COMMERCIAL / SMALL INDUSTRIAL (3)	LARGE INDUSTRIAL (4)	MUNICIPAL (5)	LIGHTING (6)
27							
28	TOTAL DISTRIBUTION EXPENSES	15,279,061	7,035,964	6,903,515	512,638	93,422	733,522
	OPEF						
1	CUSTOMER ACCOUNTS EXPENSES						
2	OPERATION						
3	901-SUPERVISION & ENGR	162,910	127,583	24,065	10,145	925	191
4	902-METER READING	480,793	386,278	90,625	42	3,847	-
5	903-CUST ACCT & COLL-GENL	-	-	-	-	-	-
6	CUST ACCT & COLL-BILLING	4,065,728	3,170,119	572,491	296,048	21,486	5,585
7	FACTORING EXP	-	-	-	-	-	-
8	INTEREST ON CUSTOMER DEPOSITS	-	-	-	-	-	-
9	TOTAL 903	4,065,728	3,170,119	572,491	296,048	21,486	5,585
10	904-UNCOLLECTABLE	348,857	144,866	159,540	30,107	2,035	12,310
11	905-MISCELLANEOUS	25,304	19,817	3,738	1,576	144	30
12	TOT CUSTOMER ACCOUNTS	5,083,592	3,848,663	850,459	337,917	28,437	18,115
13							
14	CUSTOMER INFORMATION						
15	OPERATION						
16	907-SUPERVISION	218,846	106,439	70,815	17,070	1,152	23,370
17	908-CUSTOMER ASSISTANCE						
18	CUSTOMER ASSISTANCE	758,779	369,042	245,530	59,187	3,993	81,028

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TOTAL AR RETAIL JURISDICTION (1)	RESIDENTIAL (2)	COMMERCIAL / SMALL INDUSTRIAL (3)	LARGE INDUSTRIAL (4)	MUNICIPAL (5)	LIGHTING (6)
19	ENERY EFFIC INCENTIVE AMORT	-	-	-	-	-	-
20	TOTAL ACCOUNT 908	758,779	369,042	245,530	59,187	3,993	81,028
21	909-INFO & INSTRUCTION	3,146	1,530	1,018	245	17	336
22	910-MISC CUSTOMER SERVICE	1,860	905	602	145	10	199
23	TOT CUSTOMER INFO	982,631	477,915	317,964	76,647	5,171	104,933
24							
25	CONSUMER SERVICES						
26	OPERATION						
27	911-SUPERVISION	70	34	23	5	0	7
28	912-DEMO & SELLING	36,201	17,607	11,714	2,824	190	3,866
29	913-ADVERTISING	(4,878)	(2,372)	(1,578)	(380)	(26)	(521)
30	916-MISC SALES EXP	-	-	-	-	-	-
31	TOT CONSUMER SVCS	31,393	15,268	10,158	2,449	165	3,352
32							
33	ADMINISTRATIVE & GENERAL EXP						
34	920-ADMINISTRATIVE AND GENERAL	6,926,902	3,105,760	2,983,984	626,023	36,600	174,535
35	921-OFFICE SUPPLIES AND EXPNESES	504,340	226,127	217,261	45,580	2,665	12,708
36	922-ADMIN EXPENSE TRANSFERRED	(743,649)	(333,424)	(320,350)	(67,208)	(3,929)	(18,737)
37	923-OUTSIDE SERVICES	3,560,659	1,596,465	1,533,867	321,797	18,814	89,717
38	924-PROPERTY INSURANCE	421,288	174,297	199,933	37,914	2,076	7,068
39	925-INJURIES AND DAMAGES	871,310	390,663	375,345	78,745	4,604	21,954
40	926-EMPLOYEE PENSION AND BENEFITS	2,015,988	903,892	868,451	182,196	10,652	50,796
41	928-REGULATORY COMMISSION EXPENSE - Ark	-	-	-	-	-	-
42	928-REGULATORY COMMISSION EXPENSE - La	-	-	-	-	-	-

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TOTAL AR RETAIL JURISDICTION (1)	RESIDENTIAL (2)	COMMERCIAL / SMALL INDUSTRIAL (3)	LARGE INDUSTRIAL (4)	MUNICIPAL (5)	LIGHTING (6)
43	928-REGULATORY COMMISSION EXPENSE - Tx	-	-	-	-	-	-
44	928-REGULATORY COMMISSION EXPENSE - FERC	-	-	-	-	-	-
45	928-REGULATORY COMMISSION EXPENSE	-	-	-	-	-	-
46	9301-GENERAL ADVERTISING EXPENSE	58,078	26,118	24,984	5,230	308	1,437
47	9302-MISCELLANEOUS GENERAL EXPENSE	338,858	151,931	145,974	30,625	1,790	8,538
48	931-RENTS	180,923	65,514	90,725	22,514	864	1,306
49	935-MAINTENANCE OF GENERAL PLANT	1,265,309	458,182	634,497	157,457	6,040	9,133
50		-	-	-	-	-	-
51	TOT ADMIN & GEN EXP	15,400,005	6,765,525	6,754,670	1,440,874	80,483	358,453
52							
53	TOTAL OPERATION & MAINT EXP	96,271,860	40,263,243	44,270,970	9,796,065	494,995	1,446,587
1	DEPRECIATION EXPENSE - ACCT 403						
2	PRODUCTION PLANT	17,938,861	7,234,154	8,635,822	1,897,946	75,684	95,255
3	TRANSMISSION PLANT	9,572,535	3,710,444	4,643,054	1,171,160	45,954	1,923
4	DISTRIBUTION PLANT	13,822,581	6,338,604	6,254,616	497,078	82,599	649,684
5	GENERAL PLANT	1,038,049	375,889	520,536	129,176	4,955	7,492
6	SUBTOTAL DEPRECIATION EXPENSE	42,372,026	17,659,091	20,054,029	3,695,359	209,192	754,355
7							
8	AMORTIZATION EXPENSE						
9	404-INTANGIBLE PLANT	4,031,697	1,807,660	1,736,782	364,367	21,302	101,585
10	406-PLANT ACQ ADJUSTMENT	-	-	-	-	-	-

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CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TOTAL AR RETAIL JURISDICTION	RESIDENTIAL	COMMERCIAL / SMALL INDUSTRIAL	LARGE INDUSTRIAL	MUNICIPAL	LIGHTING
		(1)	(2)	(3)	(4)	(5)	(6)
11	4073-Amortization Exp Ark	542,500	225,277	248,097	46,818	3,165	19,142
12	4073-Amortization Exp La	-	-	-	-	-	-
13	4073-Amortization Exp Tx	-	-	-	-	-	-
14	4073-Amortization Exp Tx	-	-	-	-	-	-
15	Accretion	506,838	211,231	239,879	44,202	2,502	9,023
16	SUBTOTAL AMORTIZATION	5,081,035	2,244,169	2,224,758	455,388	26,970	129,751
17							
18	TOTAL DEPRECIATION & AMORT EXP	47,453,060	19,903,260	22,278,786	4,150,747	236,161	884,106
19							
20	SO2 ALLOWANCE	120,372	48,542	57,947	12,735	508	639
21							
22	TAXES OTHER THAN INCOME TAX						
23	NON REVENUE RELATED TAXES		-	-	-	-	-
24							
25	PAYROLL RELATED TAXES	1,536,003	688,686	661,682	138,817	8,116	38,702
26	PLANT RELATED TAXES	12,366,538	5,116,346	5,868,872	1,112,932	60,926	207,462
27	STATE FRANCHISE (DEL, NE, OK)	6,474	2,690	3,061	571	33	120
28							
29	TOTAL NON-REV RELATED TAX	13,909,015	5,807,722	6,533,615	1,252,321	69,075	246,284
1	REVENUE RELATED TAXES						
2	REVENUE RELATED TAXES ARK	575,313	238,903	263,103	49,650	3,356	20,300

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TOTAL AR RETAIL JURISDICTION (1)	RESIDENTIAL (2)	COMMERCIAL / SMALL INDUSTRIAL (3)	LARGE INDUSTRIAL (4)	MUNICIPAL (5)	LIGHTING (6)
3	REVENUE RELATED TAXES LA	-	-	-	-	-	-
4	REVENUE RELATED TAXES TX	-	-	-	-	-	-
5							
6	TOTAL REVENUE-RELATED TAX	575,313	238,903	263,103	49,650	3,356	20,300
7							
8	TOT TAX OTHER THAN INCOME	14,484,328	6,046,625	6,796,718	1,301,971	72,431	266,584
WOR							
	FEDERAL INCOME TAX CALCULATION - PRESENT						
1	TOTAL REVENUES	156,932,888	65,093,783	71,767,758	14,129,291	888,984	5,053,071
2	LESS: EXPENSES	-	-	-	-	-	-
3	TOTAL OPER & MAINT EXPENSE	96,392,232	40,311,785	44,328,917	9,808,800	495,503	1,447,226
4	TOTAL DEPRECIATION EXPENSE	47,453,060	19,903,260	22,278,786	4,150,747	236,161	884,106
5	TOT TAX OTHER THAN INCOME	14,484,328	6,046,625	6,796,718	1,301,971	72,431	266,584
6	TOTAL EXPENSES	158,329,621	66,261,670	73,404,422	15,261,518	804,096	2,597,916
7	OPERATING INCOME BEFORE TAXES	(1,396,733)	(1,167,887)	(1,636,664)	(1,132,226)	84,888	2,455,156
8							
9	LESS: INTEREST	19,004,497	7,895,824	8,984,740	1,677,115	95,756	351,062
10							
11	PLUS: SCHEDULE M DIFFERENCES						
12	PERMANENT						
13	DEPRECIATION EXP RELATED	1,204,968	502,186	570,293	105,088	5,949	21,452
14	ENERGY RELATED	(2,746,437)	(830,563)	(1,457,107)	(416,028)	(15,317)	(27,422)
15	TOTAL PAYROLL RELATED	85,486	38,329	36,826	7,726	452	2,154

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CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TOTAL AR RETAIL JURISDICTION (1)	RESIDENTIAL (2)	COMMERCIAL / SMALL INDUSTRIAL (3)	LARGE INDUSTRIAL (4)	MUNICIPAL (5)	LIGHTING (6)
16	PLANT RELATED	-	-	-	-	-	-
17	INTANGIBLE PLANT RELATED	-	-	-	-	-	-
18	TEMPORARY		-	-	-	-	-
19	RETAIL CUSTOMER RELATED	-	-	-	-	-	-
20	RETAIL PROD DEMAND RELATED	-	-	-	-	-	-
21	DEPRECIATION EXP RELATED	(4,284,759)	(1,785,729)	(2,027,911)	(373,683)	(21,154)	(76,282)
22	DISTRIBUTION PLANT RELATED	474,135	217,424	214,543	17,051	2,833	22,285
23	ENERGY RELATED	(949,282)	(287,077)	(503,636)	(143,797)	(5,294)	(9,478)
24	FUEL RELATED	-	-	-	-	-	-
25	INTANGIBLE PLANT RELATED	-	-	-	-	-	-
26	TOTAL PAYROLL RELATED	(528,550)	(236,982)	(227,690)	(47,768)	(2,793)	(13,318)
27	MINE RECLAMATION	-	-	-	-	-	-
28	PLANT RELATED	(5,715,138)	(2,364,496)	(2,712,272)	(514,336)	(28,157)	(95,878)
29	RATE BASE RELATED	(24,583)	(10,213)	(11,622)	(2,169)	(124)	(454)
30	AVAILABLE	-	-	-	-	-	-
31	AVAILABLE	-	-	-	-	-	-
32	TOTAL DEDUCTIONS	(12,484,160)	(4,757,121)	(6,118,576)	(1,367,918)	(63,605)	(176,941)
33							
34	ADJUSTED INCOME	(32,885,391)	(13,820,833)	(16,739,980)	(4,177,259)	(74,473)	1,927,153
35							
36	LESS:						
37	SIT DEDUCTION	(1,040,062)	(436,806)	(527,834)	(130,396)	(2,479)	57,452
38	SIT DEDUCTION	-	-	-	-	-	-
39	SIT DEDUCTION	-	-	-	-	-	-

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CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TOTAL AR RETAIL JURISDICTION (1)	RESIDENTIAL (2)	COMMERCIAL / SMALL INDUSTRIAL (3)	LARGE INDUSTRIAL (4)	MUNICIPAL (5)	LIGHTING (6)
40							
41	FEDERAL TAXABLE INCOME	(31,845,328)	(13,384,027)	(16,212,146)	(4,046,863)	(71,994)	1,869,701
42							
43	TAX AT PRESENT BEFORE CREDITS	(6,687,519)	(2,810,646)	(3,404,551)	(849,841)	(15,119)	392,637
44							
45	AFTER TAX PROVISIONS						
46	CURRENT SIT	(1,040,062)	(436,806)	(527,834)	(130,396)	(2,479)	57,452
47	DEFERRED SIT	(686,111)	(288,153)	(348,203)	(86,020)	(1,635)	37,900
48	DEFERRED FIT	2,315,917	938,085	1,106,403	223,588	11,485	36,356
49	DEFERRED - EXCESS	(1,916,163)	(792,765)	(909,366)	(172,446)	(9,440)	(32,146)
50	ITC	(76,745)	(31,751)	(36,421)	(6,907)	(378)	(1,287)
51							
52	INCOME TAXES CHARGED TO UTILITY	(8,090,683)	(3,422,035)	(4,119,972)	(1,022,021)	(17,567)	490,913
	LOUISIANA INCOME TAX CALCULATION						
1	NET INCOME FROM LOUISIANA SOURCES	-	-	-	-	-	-
2	Deductible State Tax Expense (States other than LA)	-	-	-	-	-	-
3	INC SUBJECT TO APPORTIONMENT	-	-	-	-	-	-
4	INC APPORTIONED AT PLANT	-	-	-	-	-	-
5	RENTS/ROYALTIES - LA ONLY	-	-	-	-	-	-
6	LA FEDERAL INC TAX DED	-	-	-	-	-	-
7	LOUISIANA TAXABLE INCOME	-	-	-	-	-	-

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		TOTAL AR RETAIL JURISDICTION (1)	RESIDENTIAL (2)	COMMERCIAL / SMALL INDUSTRIAL (3)	LARGE INDUSTRIAL (4)	MUNICIPAL (5)	LIGHTING (6)
8	LA TAXES CHARGED TO UTILITY	-	-	-	-	-	-
	ARKANSAS INCOME TAX CALCULATION						
1	FEDERAL TAXABLE INCOME	102,277,594	42,985,459	52,068,524	12,997,305	231,222	(6,004,916)
2							
3	PLUS:						
4	Deductible State Tax Expense (States other than AR)	(2,254,141)	(932,595)	(1,069,763)	(202,862)	(11,105)	(37,816)
5	BONUS DEPRECIATION	(149,025,000)	(62,632,564)	(75,867,172)	(18,937,905)	(336,905)	8,749,546
6	1999 CAPITAL LOSSES / GAINS	-	-	-	-	-	-
7							
8	INC SUBJECT TO APPORTIONMENT	(49,001,547)	(20,579,700)	(24,868,411)	(6,143,462)	(116,789)	2,706,815
9							
10	INC APPORTIONED AT 0.243859	(11,949,468)	(5,018,545)	(6,064,386)	(1,498,139)	(28,480)	660,081
11	AR TAXES CHARGED TO UTILITY	(776,715)	(326,205)	(394,185)	(97,379)	(1,851)	42,905
12							
13	TEXAS GROSS RECEIPTS TAX	-	-	-	-	-	-
14	OTHER STATE INCOME TAX	(263,347)	(110,601)	(133,649)	(33,017)	(628)	14,547
15							
16	TOTAL STATE INCOME TAXES	(1,040,062)	(436,806)	(527,834)	(130,396)	(2,479)	57,452

Supporting Schedules

Recap Schedules

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	TOTAL AR RETAIL JURISDICTION	RESIDENTIAL	COMMERCIAL / SMALL INDUSTRIAL	LARGE INDUSTRIAL	MUNICIPAL	LIGHTING
	(1)	(2)	(3)	(4)	(5)	(6)
(a) C-1	(A) G-1					
(b) G-4						
(c) H-1						
(d) F-1.3						
WP's G-2						
WP's G-2 and G-3						
G Class WP						

Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporitng schedules. The associated plant plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classification/functionalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner different from the previous rate case and explain the basis for the change.

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

			RESIDENTIAL				
		ALLOC	BASIC (7)	WITH WATER HEAT (8)	WITH SPACE HEAT (9)	TOTAL RESIDENTIAL (10)	GENERAL UNMETERED (11)
	OPERATING REVENUES						
1	FIRM SALES OF ELECTRICITY						
2	BASE FIRM REVENUE		45,329,688		8,315,373	53,645,062	
3	FIRM FUEL REVENUES	PROPFUEL	0		0	0	
4							
5	TOTAL FIRM SALES OF ELECTRICITY		45,329,688		8,315,373	53,645,062	
6							
7	NON-FIRM SALES						
8	NON-FIRM REVENUE-DEMAND	DEMPROD	0		0	0	
9	NON-FIRM REVENUE FUEL (Capacity Revenue)	DEMPROD	0		0	0	
10	TOTAL NON-FIRM SALES		0		0	0	
11							
12	450-FORFEITED DISCOUNTS	CUST	776,676		123,362	900,037	
13							
14	451-MISCELLANEOUS SERVICE REVENUE	CUST	347,408		55,180	402,587	
15							
16	454 - RENT FROM ELECTRIC PROPERTY	DISTPLT	729,032		143,017	872,050	
17							
18	456 - OTHER ELECTRIC REVENUES						
19	GENERATION RELATED	DEMPROD	295,768		48,054	343,821	
20	GENERAL OFFICE RENTAL	GENPLT	93,572		16,903	110,476	
21	TRANS RELATED REVENUE	TRANPLT	7,305,127		1,514,623	8,819,750	
22	TOTAL OTHER ELECTRIC REVENUES		7,694,467		1,579,580	9,274,047	

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		ALLOC	RESIDENTIAL				
			BASIC	WITH WATER HEAT	WITH SPACE HEAT	TOTAL RESIDENTIAL	GENERAL UNMETERED
			(7)	(8)	(9)	(10)	(11)
23							
24	TOTAL OTHER OPERATING REVENUE		9,547,583		1,901,139	11,448,721	
25							
26	TOTAL OPERATING REVENUES		54,877,271		10,216,512	65,093,783	
	OPERATION & MAINTENANCE EXPENSE						
1	POWER PRODUCTION EXPENSES						
2	STEAM POWER GENERATION						
3	OPERATION						
4	500-SUPERVISION & ENGINEERI NG	LAB501_507	1,133,536		192,736	1,326,272	
5	501-FUEL						
6	DIRECT ASSIGNED COMMODITY FUEL	ENERGY	-		-	-	
7	DIRECT ASSIGNED OFF SYSTEM WSALE	PROPFUEL	-		-	-	
8	DIRECT ASSIGNED RETAIL NFIRM	PROPFUEL	-		-	-	
9	NON-ELIGIBLE	ENERGY	847,896		184,378	1,032,273	
10	MINE CLOSING	MINECLOSE	-		-	-	
11	AVAILABLE	MINECLOSE	-		-	-	
12	TOTAL ACCOUNT 501		847,896		184,378	1,032,273	
13	502-STEAM	PRODPLT	1,051,269		170,800	1,222,070	
14	505-ELECTRIC	PRODPLT	411,022		66,779	477,801	
15	506-MISCELLANEOUS POWER	PRODPLT	1,398,919		227,283	1,626,202	
16	507-RENTS	PRODPLT	126		20	147	
17	509-ALLOWANCE EXPENSE	PRODPLT	17,351		2,819	20,170	

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		ALLOC	RESIDENTIAL BASIC (7)	RESIDENTIAL WITH WATER HEAT (8)	RESIDENTIAL WITH SPACE HEAT (9)	TOTAL RESIDENTIAL (10)	GENERAL UNMETERED (11)
18	TOTAL STEAM OPERATION		4,860,119		844,816	5,704,934	
19	MAINTENANCE					-	
20	510-SUPERVISION & ENGINEERING	LAB511_514	242,093		50,847	292,940	
21	511-STRUCTURES	PRODPLT	191,389		31,095	222,484	
22	512-BOILER PLANT	ENERGY	2,001,793		435,296	2,437,090	
23	513-ELECTRIC PLANT	ENERGY	244,002		53,059	297,061	
24	514-MISC STEAM PLANT	PRODPLT	276,938		44,994	321,933	
25	TOTAL STEAM MAINTENANCE		2,956,215		615,292	3,571,507	
26	TOTAL STEAM GENERATION EXPENSE		7,816,334		1,460,107	9,276,441	
27	POWER PRODUCTION EXPENSES-OTHER					-	
28	OPERATION	LAB547_550	-		-	-	
29	546-OPERATION & SUPERVISION	prodplt	-		-	-	
30	547-FUEL	ENERGY	-		-	-	
31	548-GEN EXP	PRODPLT	42,873		6,966	49,839	
32	549-MISCELLANEOUS OTHER POWER GEN	PRODPLT	-		-	-	
33	550-RENTS	PRODPLT	-		-	-	
34	TOTAL OTHER POWER OPERATION		42,873		6,966	49,839	
35	MAINTENANCE					-	
36	551-SUPERVISION & ENGINEERING	LAB552_554	-		-	-	
37	552-STRUCTURES	PRODPLT	-		-	-	
38	553-GENERAL & ELECTRIC PLANT	PRODPLT	42,754		6,946	49,701	
39	554-MISCELLANEOUS OTHER GEN	PRODPLT	1,143		186	1,329	
40	TOTAL OTHER POWER MAINTENANCE		43,898		7,132	51,030	
41	TOTAL OTHER POWER		86,771		14,098	100,869	

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		ALLOC	RESIDENTIAL				
			BASIC	WITH WATER HEAT	WITH SPACE HEAT	TOTAL RESIDENTIAL	GENERAL UNMETERED
			(7)	(8)	(9)	(10)	(11)
42	OTHER GENERATION EXPENSES					-	
43	555-PURCHASED POWER DEMAND	DEMPROD	610,352		99,164	709,516	
44	555-PURCHASED POWER ENERGY	ENERGY	-		-	-	
45	555-PURCHASED POWER FUEL	ENERGY	-		-	-	
46	TOTAL ACCOUNT 555		610,352		99,164	709,516	
47	556-SYSTEM DISPATCHING	PRODPLT	129,655		21,065	150,720	
48	557-Fuel Related	FUELADJ	-		-	-	
49	557-OTHER	PRODPLT	249,134		40,477	289,611	
50	TOTAL OTHER PRODUCTION EXPENSE		989,141		160,706	1,149,847	
51	TOTAL PRODUCTION O&M EXPENSE		8,892,246		1,634,911	10,527,157	
						-	
	OPERATION & MAINTENANCE EXPENSE					-	
						-	
1	TRANSMISSION EXPENSES					-	
2	OPERATION					-	
3	560-SUPERVISION & ENGR	LAB561_567	487,325		101,040	588,365	
4	561-LOAD DISPATCHING	TRANPLT	940,357		194,971	1,135,328	
5	562-STATION EQUIPMENT	TRANSUB	35,234		7,305	42,539	
6	563-OVERHEAD LINES	TRANOHLN	27,807		5,765	33,572	
7	564-UNDERGROUND LINES	TRANUGLN	-		-	-	
8	565-TRANSMISSION FOR OTHERS		-			-	
9	OATT AFFILIATED	TRANPLT	-		-	-	
10	SPP FEES	SPPDEMAND	6,930,631		1,436,976	8,367,607	
11	3RD PARTY WHEELING	ENERGY	-		-	-	

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		ALLOC	RESIDENTIAL				
			BASIC	WITH WATER HEAT	WITH SPACE HEAT	TOTAL RESIDENTIAL	GENERAL UNMETERED
			(7)	(8)	(9)	(10)	(11)
12	TOTAL TRANSMISSION BY OTHERS		6,930,631		1,436,976	8,367,607	
13	566-MISC TRANSMISSION	TRANPLT	128,290		26,599	154,890	
14	566-MISC TRANSMISSION SPP	SPPDEMAND	-		-	-	
15	567-RENTS	TRANPLT	2,409		499	2,909	
16	5757-SPP Admin-MAM&SC	DEMTRANS	99,158		20,559	119,717	
17	TOTAL TRANSMISSION OPERATION		8,651,211		1,793,716	10,444,927	
18						-	
19	MAINTENANCE					-	
20	568-SUPERVISION & ENGR	LAB569_573	2,697		559	3,256	
21	569-STRUCTURES	TRANSUB	37,581		7,792	45,373	
22	570-STATION EQUIPMENT	TRANSUB	230,763		47,846	278,609	
23	571-OVERHEAD LINES	TRANOHLN	677,085		140,385	817,470	
24	571-OVERHEAD LINES	DEMTRANS	-		-	-	
25	572-UNDERGROUND LINES	TRANUGLN	62		13	75	
26	573-MISCELLANEOUS	TRANPLT	2,518		522	3,040	
27	TOTAL TRANSMISSION MAINTENANCE		950,706		197,117	1,147,823	
28						-	
29	TOTAL TRANSMISSION O&M EXP		9,601,917		1,990,833	11,592,750	
						-	
						-	
	OPERATION & MAINTENANCE EXPENSE					-	
						-	
1	DISTRIBUTION EXPENSES					-	
2	OPERATION					-	

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Schedule: G-3
Cost of Service Study - Revenue and Expense Detail
Class

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

			RESIDENTIAL				
		ALLOC	BASIC	WITH WATER HEAT	WITH SPACE HEAT	TOTAL RESIDENTIAL	GENERAL UNMETERED
			(7)	(8)	(9)	(10)	(11)
3	580-SUPERVISION & ENGR	LAB581_589	195,392		36,796	232,188	
4	581-LOAD DISPATCHING	DISTPLT	2,404		472	2,875	
5	582-STATION EQUIPMENT	PLT362	36,821		7,457	44,278	
6	583-OVERHEAD LINES	DISTOHLN	227,947		46,167	274,115	
7	584-UNDERGROUND LINES	DISTUGLN	199,128		40,331	239,458	
8	585-STREET LIGHTING & SIGNAL	PLT373	-		-	-	
9	586-METERS	PLT370	399,512		63,479	462,990	
10	587-CUST INSTALLATION	PLT371	-		-	-	
11	588-MISC DISTRIBUTION	DISTPLT	1,462,347		286,875	1,749,222	
12	589-RENTS	DISTPLT	67,992		13,338	81,330	
13	TOTAL DISTRIBUTION OPERATION		2,591,543		494,915	3,086,457	
14						-	
15	MAINTENANCE					-	
16	590-SUPERVISION & ENGR	LAB591_598	27,027		5,384	32,411	
17	591-STRUCTURES	PLT361	2,386		483	2,870	
18	592-STATION EQUIPMENT	PLT362	58,739		11,897	70,636	
19	593-OVERHEAD LINES	DISTOHLN	1,817,706		368,150	2,185,856	
20	593-OVERHEAD LINES	DISTPLT	1,230,160		241,326	1,471,486	
21	594-UNDERGROUND LINES	DISTUGLN	94,903		19,221	114,124	
22	595-LINE TRANSFORMERS	PLT368	7,009		1,420	8,429	
23	596-STREET LIGHTING & SIGNAL	PLT373	-		-	-	
24	597-METERS	PLT370	54,964		8,733	63,697	
25	598-MISCELLANEOUS PLANT	PLT371	-		-	-	
26	TOTAL DISTRIBUTION MAINTENANCE	demtrans	3,292,894		656,613	3,949,507	

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		ALLOC	RESIDENTIAL BASIC (7)	RESIDENTIAL WITH WATER HEAT (8)	RESIDENTIAL WITH SPACE HEAT (9)	TOTAL RESIDENTIAL (10)	GENERAL UNMETERED (11)
27						-	
28	TOTAL DISTRIBUTION EXPENSES		5,884,436		1,151,528	7,035,964	
						-	
						-	
	OPEF					-	
						-	
1	CUSTOMER ACCOUNTS EXPENSES					-	
2	OPERATION					-	
3	901-SUPERVISION & ENGR	LAB902_905	111,361		16,223	127,583	
4	902-METER READING	CUST902	333,202		53,076	386,278	
5	903-CUST ACCT & COLL-GENL	CUSER5	-		-	-	
6	CUST ACCT & COLL-BILLING	CUST903	2,772,702		397,417	3,170,119	
7	FACTORING EXP	REVSALES	-		-	-	
8	INTEREST ON CUSTOMER DEPOSITS	CUSTDEPA	-		-	-	
9	TOTAL 903		2,772,702		397,417	3,170,119	
10	904-UNCOLLECTABLE	REVSALES	122,411		22,455	144,866	
11	905-MISCELLANEOUS	LAB902_903	17,297		2,520	19,817	
12	TOT CUSTOMER ACCOUNTS		3,356,972		491,690	3,848,663	
13						-	
14	CUSTOMER INFORMATION					-	
15	OPERATION					-	
16	907-SUPERVISION	LAB908_910	90,489		15,950	106,439	
17	908-CUSTOMER ASSISTANCE					-	
18	CUSTOMER ASSISTANCE	CUSER7	313,740		55,302	369,042	

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		ALLOC	RESIDENTIAL				
			BASIC	WITH WATER HEAT	WITH SPACE HEAT	TOTAL RESIDENTIAL	GENERAL UNMETERED
			(7)	(8)	(9)	(10)	(11)
19	ENERY EFFIC INCENTIVE AMORT	CUSER7	-		-	-	
20	TOTAL ACCOUNT 908		313,740		55,302	369,042	
21	909-INFO & INSTRUCTION	CUSER7	1,301		229	1,530	
22	910-MISC CUSTOMER SERVICE	CUSER7	769		136	905	
23	TOT CUSTOMER INFO		406,299		71,617	477,915	
24						-	
25	CONSUMER SERVICES					-	
26	OPERATION					-	
27	911-SUPERVISION	CUSER7	29		5	34	
28	912-DEMO & SELLING	CUSER7	14,968		2,638	17,607	
29	913-ADVERTISING	CUSER7	(2,017)		(355)	(2,372)	
30	916-MISC SALES EXP	CUSER7	-		-	-	
31	TOT CONSUMER SVCS		12,980		2,288	15,268	
32						-	
33	ADMINISTRATIVE & GENERAL EXP					-	
34	920-ADMINISTRATIVE AND GENERAL	LABORT	2,636,607		469,153	3,105,760	
35	921-OFFICE SUPPLIES AND EXPNESES	LABORT	191,968		34,159	226,127	
36	922-ADMIN EXPENSE TRANSFERRED	LABORT	(283,057)		(50,367)	(333,424)	
37	923-OUTSIDE SERVICES	LABORT	1,355,304		241,160	1,596,465	
38	924-PROPERTY INSURANCE	PLANT	147,048		27,249	174,297	
39	925-INJURIES AND DAMAGES	LABORT	331,649		59,013	390,663	
40	926-EMPLOYEE PENSION AND BENEFITS	LABORT	767,351		136,541	903,892	
41	928-REGULATORY COMMISSION EXPENSE - Ark	REVSALEAR	-		-	-	
42	928-REGULATORY COMMISSION EXPENSE - La	REVSALELA	-		-	-	

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		ALLOC	RESIDENTIAL				
			BASIC	WITH WATER HEAT	WITH SPACE HEAT	TOTAL RESIDENTIAL	GENERAL UNMETERED
			(7)	(8)	(9)	(10)	(11)
43	928-REGULATORY COMMISSION EXPENSE - Tx	REVSALETX	-		-	-	
44	928-REGULATORY COMMISSION EXPENSE - FERC	REVSALESW	-		-	-	
45	928-REGULATORY COMMISSION EXPENSE	LABORT	-		-	-	
46	9301-GENERAL ADVERTISING EXPENSE	LABORXR	22,176		3,941	26,118	
47	9302-MISCELLANEOUS GENERAL EXPENSE	LABORT	128,981		22,951	151,931	
48	931-RENTS	GENPLT	55,490		10,024	65,514	
49	935-MAINTENANCE OF GENERAL PLANT	GENPLT	388,079		70,103	458,182	
50		LABORT	-		-	-	
51	TOT ADMIN & GEN EXP		5,741,597		1,023,928	6,765,525	
52						-	
53	TOTAL OPERATION & MAINT EXP		33,896,448		6,366,795	40,263,243	
1	DEPRECIATION EXPENSE - ACCT 403						
2	PRODUCTION PLANT	PRODPLT	6,223,086		1,011,068	7,234,154	
3	TRANSMISSION PLANT	TRANPLT	3,073,246		637,198	3,710,444	
4	DISTRIBUTION PLANT	DISTPLT	5,299,065		1,039,540	6,338,604	
5	GENERAL PLANT	GENPLT	318,377		57,512	375,889	
6	SUBTOTAL DEPRECIATION EXPENSE		14,913,773		2,745,318	17,659,091	
7							
8	AMORTIZATION EXPENSE						
9	404-INTANGIBLE PLANT	LABORT	1,534,597		273,063	1,807,660	
10	406-PLANT ACQ ADJUSTMENT	DISTPLTLA	-		-	-	

SOUTHWESTERN ELECTRIC POWER COMPANY
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Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		ALLOC	RESIDENTIAL				
			BASIC	WITH WATER HEAT	WITH SPACE HEAT	TOTAL RESIDENTIAL	GENERAL UNMETERED
			(7)	(8)	(9)	(10)	(11)
11	4073-Amortization Exp Ark	REVSALEAR	190,358		34,920	225,277	
12	4073-Amortization Exp La	REVSALELA	-		-	-	
13	4073-Amortization Exp Tx	REVSALETX	-		-	-	
14	4073-Amortization Exp Tx	PRODPLTR	-		-	-	
15	Accretion	DEPEXP	178,393		32,838	211,231	
16	SUBTOTAL AMORTIZATION		1,903,347		340,821	2,244,169	
17							
18	TOTAL DEPRECIATION & AMORT EXP		16,817,121		3,086,139	19,903,260	
19							
20	SO2 ALLOWANCE	PRODPLT	41,758		6,784	48,542	
21							
22	TAXES OTHER THAN INCOME TAX						
23	NON REVENUE RELATED TAXES		-				
24							
25	PAYROLL RELATED TAXES	LABORT	584,654		104,032	688,686	
26	PLANT RELATED TAXES	PLANT	4,316,464		799,883	5,116,346	
27	STATE FRANCHISE (DEL, NE, OK)	RBX	2,263		427	2,690	
28							
29	TOTAL NON-REV RELATED TAX		4,903,380		904,341	5,807,722	
1	REVENUE RELATED TAXES						
2	REVENUE RELATED TAXES ARK	RVSALEARR	201,872		37,032	238,903	

SOUTHWESTERN ELECTRIC POWER COMPANY
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CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		ALLOC	RESIDENTIAL				
			BASIC	WITH WATER HEAT	WITH SPACE HEAT	TOTAL RESIDENTIAL	GENERAL UNMETERED
			(7)	(8)	(9)	(10)	(11)
3	REVENUE RELATED TAXES LA	RVSALELAR	-		-	-	
4	REVENUE RELATED TAXES TX	RVSALETXR	-		-	-	
5							
6	TOTAL REVENUE-RELATED TAX		201,872		37,032	238,903	
7							
8	TOT TAX OTHER THAN INCOME		5,105,252		941,373	6,046,625	
WOR							
	FEDERAL INCOME TAX CALCULATION - PRESENT						
1	TOTAL REVENUES		54,877,271		10,216,512	65,093,783	
2	LESS: EXPENSES		-				
3	TOTAL OPER & MAINT EXPENSE		33,938,206		6,373,580	40,311,785	
4	TOTAL DEPRECIATION EXPENSE		16,817,121		3,086,139	19,903,260	
5	TOT TAX OTHER THAN INCOME		5,105,252		941,373	6,046,625	
6	TOTAL EXPENSES		55,860,578		10,401,092	66,261,670	
7	OPERATING INCOME BEFORE TAXES		(983,307)		(184,580)	(1,167,887)	
8							
9	LESS: INTEREST	RBX	6,643,515		1,252,309	7,895,824	
10							
11	PLUS: SCHEDULE M DIFFERENCES						
12	PERMANENT						
13	DEPRECIATION EXP RELATED	DEPREXP	424,115		78,071	502,186	
14	ENERGY RELATED	ENERGY	(682,213)		(148,350)	(830,563)	
15	TOTAL PAYROLL RELATED	LABORT	32,539		5,790	38,329	

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CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		ALLOC	RESIDENTIAL				
			BASIC	WITH WATER HEAT	WITH SPACE HEAT	TOTAL RESIDENTIAL	GENERAL UNMETERED
			(7)	(8)	(9)	(10)	(11)
16	PLANT RELATED	PLANT	-		-	-	
17	INTANGIBLE PLANT RELATED	INTPLT	-		-	-	
18	TEMPORARY		-				
19	RETAIL CUSTOMER RELATED	CUSTINFO	-		-	-	
20	RETAIL PROD DEMAND RELATED	DEMRTAIL	-		-	-	
21	DEPRECIATION EXP RELATED	DEPREXP	(1,508,116)		(277,613)	(1,785,729)	
22	DISTRIBUTION PLANT RELATED	DISTPLT	181,766		35,658	217,424	
23	ENERGY RELATED	ENERGY	(235,801)		(51,276)	(287,077)	
24	FUEL RELATED	FUEL	-		-	-	
25	INTANGIBLE PLANT RELATED	INTPLT	-		-	-	
26	TOTAL PAYROLL RELATED	LABORT	(201,184)		(35,798)	(236,982)	
27	MINE RECLAMATION	MINECLOSE	-		-	-	
28	PLANT RELATED	PLANT	(1,994,834)		(369,662)	(2,364,496)	
29	RATE BASE RELATED	RBX	(8,593)		(1,620)	(10,213)	
30	AVAILABLE	AVAIL	-		-	-	
31	AVAILABLE	AVAIL	-		-	-	
32	TOTAL DEDUCTIONS		(3,992,321)		(764,800)	(4,757,121)	
33							
34	ADJUSTED INCOME		(11,619,144)		(2,201,689)	(13,820,833)	
35							
36	LESS:						
37	SIT DEDUCTION		(367,279)		(69,527)	(436,806)	
38	SIT DEDUCTION		-		-	-	
39	SIT DEDUCTION		-		-	-	

SOUTHWESTERN ELECTRIC POWER COMPANY
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Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		ALLOC	RESIDENTIAL BASIC (7)	RESIDENTIAL WITH WATER HEAT (8)	RESIDENTIAL WITH SPACE HEAT (9)	TOTAL RESIDENTIAL (10)	GENERAL UNMETERED (11)
40							
41	FEDERAL TAXABLE INCOME		(11,251,865)		(2,132,162)	(13,384,027)	
42							
43	TAX AT PRESENT BEFORE CREDITS		(2,362,892)	-	(447,754)	(2,810,646)	
44							
45	AFTER TAX PROVISIONS						
46	CURRENT SIT		(367,279)		(69,527)	(436,806)	
47	DEFERRED SIT	SIT	(242,287)		(45,866)	(288,153)	
48	DEFERRED FIT	FITTEMP	791,020		147,065	938,085	
49	DEFERRED - EXCESS	PLANT	(668,825)		(123,940)	(792,765)	
50	ITC	PLANT	(26,787)		(4,964)	(31,751)	
51							
52	INCOME TAXES CHARGED TO UTILITY		(2,877,050)		(544,985)	(3,422,035)	

LOUISIANA INCOME TAX CALCULATION

		ALLOC	BASIC (7)	WITH WATER HEAT (8)	WITH SPACE HEAT (9)	TOTAL RESIDENTIAL (10)	GENERAL UNMETERED (11)
1	NET INCOME FROM LOUISIANA SOURCES	TAXINCLA	-		-	-	
2	Deductible State Tax Expense (States other than LA)	PLANTLA	-		-	-	
3	INC SUBJECT TO APPORTIONMENT		-		-		
4	INC APPORTIONED AT PLANT	PLANT	-		-	-	
5	RENTS/ROYALTIES - LA ONLY	PLANTLA	-		-	-	
6	LA FEDERAL INC TAX DED	PLANTLA	-		-	-	
7	LOUISIANA TAXABLE INCOME		-		-		

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
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CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		ALLOC	RESIDENTIAL BASIC (7)	RESIDENTIAL WITH WATER HEAT (8)	RESIDENTIAL WITH SPACE HEAT (9)	TOTAL RESIDENTIAL (10)	GENERAL UNMETERED (11)
8	LA TAXES CHARGED TO UTILITY	0.08000000	-		-		
	ARKANSAS INCOME TAX CALCULATION						
1	FEDERAL TAXABLE INCOME	TAXINCAR	36,137,599		6,847,860	42,985,459	
2							
3	PLUS:						
4	Deductible State Tax Expense (States other than AR)	PLANTAR	(786,794)		(145,801)	(932,595)	
5	BONUS DEPRECIATION	TAXINCAR	(52,654,794)		(9,977,770)	(62,632,564)	
6	1999 CAPITAL LOSSES / GAINS	PLANTAR	-		-	-	
7							
8	INC SUBJECT TO APPORTIONMENT		(17,303,989)		(3,275,711)	(20,579,700)	
9							
10	INC APPORTIONED AT 0.243859	0.243859	(4,219,734)		(798,812)	(5,018,545)	
11	AR TAXES CHARGED TO UTILITY	0.0650000	(274,283)	0	(51,923)	(326,205)	0
12							
13	TEXAS GROSS RECEIPTS TAX	PLANT	-		-	-	
14	OTHER STATE INCOME TAX	SIT	(92,996)		(17,605)	(110,601)	
15							
16	TOTAL STATE INCOME TAXES		(367,279)		(69,527)	(436,806)	

Supporting Schedules

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

ALLOC	RESIDENTIAL				
	BASIC	WITH WATER HEAT	WITH SPACE HEAT	TOTAL RESIDENTIAL	GENERAL UNMETERED
	(7)	(8)	(9)	(10)	(11)

(a) C-1
(b) G-4
(c) H-1
(d) F-1.3
WP's G-2
WP's G-2 and G-3
G Class WP

Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas
if the amounts brought forward from supporting schedules are at the Arka
(non-Arkansas) amounts on the supporitng schedules. The associated pl
specific plant accounts. Workpapers detailing classification/functionalizati
classified and/or allocated in a manner different from the previous rate cas

SOUTHWESTERN ELECTRIC POWER COMPANY
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CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		COMMERCIAL / SMALL INDUSTRIAL							
		LIGHT & POWER			GENERAL	C-1	LIGHT & POWER TOU		
		PRI	SEC	PRIMARY SUB	SERVICE	RIDER	SEC	PRI	TOTAL
		(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
	OPERATING REVENUES								
1	FIRM SALES OF ELECTRICITY								
2	BASE FIRM REVENUE	12,101,967	30,742,086		15,799,494		248,498	187,060	435,558
3	FIRM FUEL REVENUES	0	0		0		0	0	0
4									
5	TOTAL FIRM SALES OF ELECTRICITY	12,101,967	30,742,086		15,799,494		248,498	187,060	435,558
6									
7	NON-FIRM SALES								
8	NON-FIRM REVENUE-DEMAND	0	0		0		0	0	0
9	NON-FIRM REVENUE FUEL (Capacity Revenue)	0	0		0		0	0	0
10	TOTAL NON-FIRM SALES	0	0		0		0	0	0
11									
12	450-FORFEITED DISCOUNTS	435	14,332		142,852		18	9	27
13									
14	451-MISCELLANEOUS SERVICE REVENUE	195	6,411		63,898		8	4	12
15									
16	454 - RENT FROM ELECTRIC PROPERTY	131,713	473,359		244,804		6,566	4,052	10,618
17									
18	456 - OTHER ELECTRIC REVENUES								
19	GENERATION RELATED	85,504	226,330		95,816		934	1,855	2,789
20	GENERAL OFFICE RENTAL	35,398	83,569		32,694		402	926	1,327
21	TRANS RELATED REVENUE	2,629,407	6,005,150		2,314,125		31,947	55,942	87,889
22	TOTAL OTHER ELECTRIC REVENUES	2,750,310	6,315,048		2,442,635		33,282	58,723	92,006

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Schedule: G-3
Cost of Service Study - Revenue and Expense Detail
Class

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	COMMERCIAL / SMALL INDUSTRIAL							
	LIGHT & POWER			GENERAL	C-1	LIGHT & POWER TOU		
	PRI	SEC	PRIMARY SUB	SERVICE	RIDER	SEC	PRI	TOTAL
	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
23								
24 TOTAL OTHER OPERATING REVENUE	2,882,653	6,809,150		2,894,189		39,874	62,788	102,662
25								
26 TOTAL OPERATING REVENUES	14,984,619	37,551,236		18,693,683		288,371	249,848	538,220
OPERATION & MAINTENANCE EXPENSE								
1 POWER PRODUCTION EXPENSES								
2 STEAM POWER GENERATION								
3 OPERATION								
4 500-SUPERVISION & ENGINEERI NG	369,766	927,713		379,215		4,113	8,818	12,931
5 501-FUEL								
6 DIRECT ASSIGNED COMMODITY FUEL	-	-		-		-	-	-
7 DIRECT ASSIGNED OFF SYSTEM WSALE	-	-		-		-	-	-
8 DIRECT ASSIGNED RETAIL NFIRM	-	-		-		-	-	-
9 NON-ELIGIBLE	473,974	976,863		339,946		5,588	14,609	20,197
10 MINE CLOSING	-	-		-		-	-	-
11 AVAILABLE	-	-		-		-	-	-
12 TOTAL ACCOUNT 501	473,974	976,863		339,946		5,588	14,609	20,197
13 502-STEAM	303,914	804,460		340,567		3,318	6,594	9,912
14 505-ELECTRIC	118,823	314,525		133,154		1,297	2,578	3,876
15 506-MISCELLANEOUS POWER	404,417	1,070,491		453,191		4,416	8,775	13,190
16 507-RENTS	36	96		41		0	1	1
17 509-ALLOWANCE EXPENSE	5,016	13,278		5,621		55	109	164

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PRODUCTION ALLOCATION METHOD
4 CP A&E

		COMMERCIAL / SMALL INDUSTRIAL							
		LIGHT & POWER			GENERAL	C-1	LIGHT & POWER TOU		
		PRI	SEC	PRIMARY SUB	SERVICE	RIDER	SEC	PRI	TOTAL
		(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
18	TOTAL STEAM OPERATION	1,675,947	4,107,426		1,651,735		18,787	41,484	60,272
19	MAINTENANCE								-
20	510-SUPERVISION & ENGINEERING	126,510	266,273		94,547		1,483	3,813	5,296
21	511-STRUCTURES	55,329	146,456		62,002		604	1,201	1,805
22	512-BOILER PLANT	1,119,002	2,306,271		802,577		13,192	34,491	47,684
23	513-ELECTRIC PLANT	136,397	281,115		97,827		1,608	4,204	5,812
24	514-MISC STEAM PLANT	80,061	211,921		89,716		874	1,737	2,611
25	TOTAL STEAM MAINTENANCE	1,517,299	3,212,036		1,146,669		17,762	45,447	63,208
26	TOTAL STEAM GENERATION EXPENSE	3,193,246	7,319,463		2,798,405		36,549	86,931	123,480
27	POWER PRODUCTION EXPENSES-OTHER								-
28	OPERATION	-	-		-		-	-	-
29	546-OPERATION & SUPERVISION	-	-		-		-	-	-
30	547-FUEL	-	-		-		-	-	-
31	548-GEN EXP	12,394	32,808		13,889		135	269	404
32	549-MISCELLANEOUS OTHER POWER GEN	-	-		-		-	-	-
33	550-RENTS	-	-		-		-	-	-
34	TOTAL OTHER POWER OPERATION	12,394	32,808		13,889		135	269	404
35	MAINTENANCE								-
36	551-SUPERVISION & ENGINEERING	-	-		-		-	-	-
37	552-STRUCTURES	-	-		-		-	-	-
38	553-GENERAL & ELECTRIC PLANT	12,360	32,717		13,851		135	268	403
39	554-MISCELLANEOUS OTHER GEN	331	875		370		4	7	11
40	TOTAL OTHER POWER MAINTENANCE	12,691	33,592		14,221		139	275	414
41	TOTAL OTHER POWER	25,085	66,400		28,110		274	544	818

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DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		COMMERCIAL / SMALL INDUSTRIAL							
		LIGHT & POWER			GENERAL	C-1	LIGHT & POWER TOU		
		PRI	SEC	PRIMARY SUB	SERVICE	RIDER	SEC	PRI	TOTAL
		(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
42	OTHER GENERATION EXPENSES								-
43	555-PURCHASED POWER DEMAND	176,448	467,058		197,728		1,927	3,828	5,755
44	555-PURCHASED POWER ENERGY	-	-		-		-	-	-
45	555-PURCHASED POWER FUEL	-	-		-		-	-	-
46	TOTAL ACCOUNT 555	176,448	467,058		197,728		1,927	3,828	5,755
47	556-SYSTEM DISPATCHING	37,482	99,216		42,003		409	813	1,223
48	557-Fuel Related	-	-		-		-	-	-
49	557-OTHER	72,023	190,644		80,709		786	1,563	2,349
50	TOTAL OTHER PRODUCTION EXPENSE	285,953	756,918		320,440		3,122	6,204	9,327
51	TOTAL PRODUCTION O&M EXPENSE	3,504,285	8,142,780		3,146,955		39,945	93,680	133,625
									-
	OPERATION & MAINTENANCE EXPENSE								-
									-
1	TRANSMISSION EXPENSES								-
2	OPERATION								-
3	560-SUPERVISION & ENGR	175,408	400,603		154,375		2,131	3,732	5,863
4	561-LOAD DISPATCHING	338,472	773,017		297,887		4,112	7,201	11,314
5	562-STATION EQUIPMENT	12,682	28,964		11,162		154	270	424
6	563-OVERHEAD LINES	10,009	22,858		8,809		122	213	335
7	564-UNDERGROUND LINES	-	-		-		-	-	-
8	565-TRANSMISSION FOR OTHERS								-
9	OATT AFFILIATED	-	-		-		-	-	-
10	SPP FEES	2,494,611	5,697,297		2,195,492		30,310	53,074	83,384
11	3RD PARTY WHEELING	-	-		-		-	-	-

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		COMMERCIAL / SMALL INDUSTRIAL							
		LIGHT & POWER			GENERAL	C-1	LIGHT & POWER TOU		
		PRI	SEC	PRIMARY SUB	SERVICE	RIDER	SEC	PRI	TOTAL
		(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
12	TOTAL TRANSMISSION BY OTHERS	2,494,611	5,697,297		2,195,492		30,310	53,074	83,384
13	566-MISC TRANSMISSION	46,177	105,461		40,640		561	982	1,543
14	566-MISC TRANSMISSION SPP	-	-		-		-	-	-
15	567-RENTS	867	1,980		763		11	18	29
16	5757-SPP Admin-MAM&SC	35,691	81,512		31,411		434	759	1,193
17	TOTAL TRANSMISSION OPERATION	3,113,917	7,111,693		2,740,539		37,834	66,250	104,084
18									-
19	MAINTENANCE								-
20	568-SUPERVISION & ENGR	971	2,217		854		12	21	32
21	569-STRUCTURES	13,527	30,893		11,905		164	288	452
22	570-STATION EQUIPMENT	83,061	189,698		73,101		1,009	1,767	2,776
23	571-OVERHEAD LINES	243,710	556,595		214,488		2,961	5,185	8,146
24	571-OVERHEAD LINES	-	-		-		-	-	-
25	572-UNDERGROUND LINES	22	51		20		0	0	1
26	573-MISCELLANEOUS	906	2,070		798		11	19	30
27	TOTAL TRANSMISSION MAINTENANCE	342,197	781,524		301,166		4,158	7,280	11,438
28									-
29	TOTAL TRANSMISSION O&M EXP	3,456,114	7,893,217		3,041,704		41,992	73,531	115,522
									-
									-
	OPERATION & MAINTENANCE EXPENSE								-
									-
1	DISTRIBUTION EXPENSES								-
2	OPERATION								-

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		COMMERCIAL / SMALL INDUSTRIAL							
		LIGHT & POWER			GENERAL	C-1	LIGHT & POWER TOU		
		PRI	SEC	PRIMARY SUB	SERVICE	RIDER	SEC	PRI	TOTAL
		(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
3	580-SUPERVISION & ENGR	27,763	106,775		67,415		1,399	834	2,233
4	581-LOAD DISPATCHING	434	1,561		807		22	13	35
5	582-STATION EQUIPMENT	10,698	27,491		12,736		388	331	719
6	583-OVERHEAD LINES	41,713	170,190		78,845		2,400	1,290	3,690
7	584-UNDERGROUND LINES	24,805	148,673		68,877		2,097	767	2,864
8	585-STREET LIGHTING & SIGNAL	-	-		-		-	-	-
9	586-METERS	15,838	60,102		146,213		87	310	397
10	587-CUST INSTALLATION	-	-		-		-	-	-
11	588-MISC DISTRIBUTION	264,200	949,500		491,047		13,170	8,128	21,298
12	589-RENTS	12,284	44,147		22,831		612	378	990
13	TOTAL DISTRIBUTION OPERATION	397,734	1,508,438		888,771		20,174	12,051	32,225
14									-
15	MAINTENANCE								-
16	590-SUPERVISION & ENGR	4,655	18,944		9,390		263	143	406
17	591-STRUCTURES	693	1,782		825		25	21	47
18	592-STATION EQUIPMENT	17,066	43,856		20,317		619	528	1,146
19	593-OVERHEAD LINES	332,626	1,357,132		628,731		19,141	10,285	29,426
20	593-OVERHEAD LINES	222,251	798,741		413,080		11,079	6,837	17,916
21	594-UNDERGROUND LINES	11,822	70,856		32,826		999	366	1,365
22	595-LINE TRANSFORMERS	2,036	5,233		2,424		74	63	137
23	596-STREET LIGHTING & SIGNAL	-	-		-		-	-	-
24	597-METERS	2,179	8,269		20,116		12	43	55
25	598-MISCELLANEOUS PLANT	-	-		-		-	-	-
26	TOTAL DISTRIBUTION MAINTENANCE	593,329	2,304,811		1,127,710		32,211	18,286	50,497

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		COMMERCIAL / SMALL INDUSTRIAL							
		LIGHT & POWER			GENERAL	C-1	LIGHT & POWER TOU		
		PRI	SEC	PRIMARY SUB	SERVICE	RIDER	SEC	PRI	TOTAL
		(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
27									-
28	TOTAL DISTRIBUTION EXPENSES	991,063	3,813,249		2,016,481		52,385	30,337	82,722
									-
									-
OPEF									-
									-
1	CUSTOMER ACCOUNTS EXPENSES								-
2	OPERATION								-
3	901-SUPERVISION & ENGR	60	1,983		19,760		1,477	785	2,262
4	902-METER READING	251	8,243		82,116		11	4	15
5	903-CUST ACCT & COLL-GENL	-	-		-		-	-	-
6	CUST ACCT & COLL-BILLING	1,398	46,054		459,041		43,082	22,916	65,999
7	FACTORING EXP	-	-		-		-	-	-
8	INTEREST ON CUSTOMER DEPOSITS	-	-		-		-	-	-
9	TOTAL 903	1,398	46,054		459,041		43,082	22,916	65,999
10	904-UNCOLLECTABLE	32,681	83,017		42,666		671	505	1,176
11	905-MISCELLANEOUS	9	308		3,069		229	122	351
12	TOT CUSTOMER ACCOUNTS	34,400	139,605		606,652		45,471	24,333	69,803
13									-
14	CUSTOMER INFORMATION								-
15	OPERATION								-
16	907-SUPERVISION	15,499	32,177		22,483		179	477	656
17	908-CUSTOMER ASSISTANCE								-
18	CUSTOMER ASSISTANCE	53,739	111,564		77,953		620	1,654	2,274

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

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PRODUCTION ALLOCATION METHOD
4 CP A&E

		COMMERCIAL / SMALL INDUSTRIAL							
		LIGHT & POWER			GENERAL	C-1	LIGHT & POWER TOU		
		PRI	SEC	PRIMARY SUB	SERVICE	RIDER	SEC	PRI	TOTAL
		(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
19	ENERY EFFIC INCENTIVE AMORT	-	-		-		-	-	-
20	TOTAL ACCOUNT 908	53,739	111,564		77,953		620	1,654	2,274
21	909-INFO & INSTRUCTION	223	463		323		3	7	9
22	910-MISC CUSTOMER SERVICE	132	273		191		2	4	6
23	TOT CUSTOMER INFO	69,593	144,477		100,950		803	2,142	2,945
24									-
25	CONSUMER SERVICES								-
26	OPERATION								-
27	911-SUPERVISION	5	10		7		0	0	0
28	912-DEMO & SELLING	2,564	5,323		3,719		30	79	108
29	913-ADVERTISING	(345)	(717)		(501)		(4)	(11)	(15)
30	916-MISC SALES EXP	-	-		-		-	-	-
31	TOT CONSUMER SVCS	2,223	4,616		3,225		26	68	94
32									-
33	ADMINISTRATIVE & GENERAL EXP								-
34	920-ADMINISTRATIVE AND GENERAL	590,618	1,558,003		796,647		18,938	19,778	38,716
35	921-OFFICE SUPPLIES AND EXPNESES	43,002	113,437		58,003		1,379	1,440	2,819
36	922-ADMIN EXPENSE TRANSFERRED	(63,407)	(167,262)		(85,525)		(2,033)	(2,123)	(4,156)
37	923-OUTSIDE SERVICES	303,597	800,866		409,503		9,735	10,166	19,901
38	924-PROPERTY INSURANCE	40,310	109,750		48,115		800	959	1,759
39	925-INJURIES AND DAMAGES	74,292	195,976		100,207		2,382	2,488	4,870
40	926-EMPLOYEE PENSION AND BENEFITS	171,892	453,437		231,854		5,512	5,756	11,268
41	928-REGULATORY COMMISSION EXPENSE - Ark	-	-		-		-	-	-
42	928-REGULATORY COMMISSION EXPENSE - La	-	-		-		-	-	-

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

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PRODUCTION ALLOCATION METHOD
4 CP A&E

		COMMERCIAL / SMALL INDUSTRIAL							
		LIGHT & POWER			GENERAL	C-1	LIGHT & POWER TOU		
		PRI	SEC	PRIMARY SUB	SERVICE	RIDER	SEC	PRI	TOTAL
		(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
43	928-REGULATORY COMMISSION EXPENSE - Tx	-	-		-		-	-	-
44	928-REGULATORY COMMISSION EXPENSE - FERC	-	-		-		-	-	-
45	928-REGULATORY COMMISSION EXPENSE	-	-		-		-	-	-
46	9301-GENERAL ADVERTISING EXPENSE	4,937	13,012		6,713		157	165	321
47	9302-MISCELLANEOUS GENERAL EXPENSE	28,893	76,216		38,971		926	968	1,894
48	931-RENTS	20,992	49,558		19,388		238	549	787
49	935-MAINTENANCE OF GENERAL PLANT	146,809	346,589		135,594		1,665	3,840	5,505
50		-	-		-		-	-	-
51	TOT ADMIN & GEN EXP	1,361,935	3,549,581		1,759,470		39,699	43,985	83,683
52									-
53	TOTAL OPERATION & MAINT EXP	9,419,613	23,687,524		10,675,438		220,320	268,075	488,395
1	DEPRECIATION EXPENSE - ACCT 403								
2	PRODUCTION PLANT	1,799,049	4,762,076		2,016,019		19,643	39,035	58,678
3	TRANSMISSION PLANT	1,106,184	2,526,349		973,546		13,440	23,535	36,975
4	DISTRIBUTION PLANT	957,374	3,440,674		1,779,392		47,723	29,453	77,176
5	GENERAL PLANT	120,441	284,339		111,240		1,366	3,150	4,516
6	SUBTOTAL DEPRECIATION EXPENSE	3,983,048	11,013,438		4,880,197		82,172	95,173	177,345
7									
8	AMORTIZATION EXPENSE								
9	404-INTANGIBLE PLANT	343,760	906,812		463,676		11,023	11,511	22,534
10	406-PLANT ACQ ADJUSTMENT	-	-		-		-	-	-

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4 CP A&E

		COMMERCIAL / SMALL INDUSTRIAL							
		LIGHT & POWER			GENERAL	C-1	LIGHT & POWER TOU		
		PRI	SEC	PRIMARY SUB	SERVICE	RIDER	SEC	PRI	TOTAL
		(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
11	4073-Amortization Exp Ark	50,821	129,099		66,349		1,044	786	1,829
12	4073-Amortization Exp La	-	-		-		-	-	-
13	4073-Amortization Exp Tx	-	-		-		-	-	-
14	4073-Amortization Exp Tx	-	-		-		-	-	-
15	Accretion	47,644	131,739		58,375		983	1,138	2,121
16	SUBTOTAL AMORTIZATION	442,225	1,167,649		588,399		13,049	13,435	26,484
17									
18	TOTAL DEPRECIATION & AMORT EXP	4,425,273	12,181,087		5,468,596		95,221	108,608	203,830
19									
20	SO2 ALLOWANCE	12,072	31,954		13,528		132	262	394
21									
22	TAXES OTHER THAN INCOME TAX								
23	NON REVENUE RELATED TAXES								
24									
25	PAYROLL RELATED TAXES	130,966	345,479		176,652		4,199	4,386	8,585
26	PLANT RELATED TAXES	1,183,259	3,221,604		1,412,388		23,473	28,147	51,620
27	STATE FRANCHISE (DEL, NE, OK)	615	1,677		740		13	15	28
28									
29	TOTAL NON-REV RELATED TAX	1,314,841	3,568,760		1,589,780		27,686	32,547	60,233
1	REVENUE RELATED TAXES								
2	REVENUE RELATED TAXES ARK	53,895	136,907		70,362		1,107	833	1,940

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	COMMERCIAL / SMALL INDUSTRIAL							
	LIGHT & POWER			GENERAL	C-1	LIGHT & POWER TOU		
	PRI	SEC	PRIMARY SUB	SERVICE	RIDER	SEC	PRI	TOTAL
	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
3 REVENUE RELATED TAXES LA	-	-		-		-	-	-
4 REVENUE RELATED TAXES TX	-	-		-		-	-	-
5								
6 TOTAL REVENUE-RELATED TAX	53,895	136,907		70,362		1,107	833	1,940
7								
8 TOT TAX OTHER THAN INCOME	1,368,736	3,705,667		1,660,142		28,793	33,380	62,173
WOR								
FEDERAL INCOME TAX CALCULATION - PRESENT								
1 TOTAL REVENUES	14,984,619	37,551,236		18,693,683		288,371	249,848	538,220
2 LESS: EXPENSES								
3 TOTAL OPER & MAINT EXPENSE	9,431,685	23,719,478		10,688,966		220,452	268,336	488,789
4 TOTAL DEPRECIATION EXPENSE	4,425,273	12,181,087		5,468,596		95,221	108,608	203,830
5 TOT TAX OTHER THAN INCOME	1,368,736	3,705,667		1,660,142		28,793	33,380	62,173
6 TOTAL EXPENSES	15,225,694	39,606,232		17,817,704		344,466	410,325	754,791
7 OPERATING INCOME BEFORE TAXES	(241,075)	(2,054,996)		875,979		(56,095)	(160,477)	(216,572)
8								
9 LESS: INTEREST	1,806,804	4,922,056		2,173,285		38,573	44,022	82,595
10								
11 PLUS: SCHEDULE M DIFFERENCES								
12 PERMANENT								
13 DEPRECIATION EXP RELATED	113,269	313,198		138,782		2,337	2,707	5,043
14 ENERGY RELATED	(381,357)	(785,980)		(273,519)		(4,496)	(11,755)	(16,251)
15 TOTAL PAYROLL RELATED	7,289	19,228		9,832		234	244	478

SOUTHWESTERN ELECTRIC POWER COMPANY
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4 CP A&E

	COMMERCIAL / SMALL INDUSTRIAL							
	LIGHT & POWER			GENERAL	C-1	LIGHT & POWER TOU		
	PRI	SEC	PRIMARY SUB	SERVICE	RIDER	SEC	PRI	TOTAL
	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
16 PLANT RELATED	-	-		-		-	-	-
17 INTANGIBLE PLANT RELATED	-	-		-		-	-	-
18 TEMPORARY								
19 RETAIL CUSTOMER RELATED	-	-		-		-	-	-
20 RETAIL PROD DEMAND RELATED	-	-		-		-	-	-
21 DEPRECIATION EXP RELATED	(402,775)	(1,113,705)		(493,497)		(8,309)	(9,624)	(17,934)
22 DISTRIBUTION PLANT RELATED	32,839	118,020		61,036		1,637	1,010	2,647
23 ENERGY RELATED	(131,813)	(271,667)		(94,539)		(1,554)	(4,063)	(5,617)
24 FUEL RELATED	-	-		-		-	-	-
25 INTANGIBLE PLANT RELATED	-	-		-		-	-	-
26 TOTAL PAYROLL RELATED	(45,067)	(118,882)		(60,787)		(1,445)	(1,509)	(2,954)
27 MINE RECLAMATION	-	-		-		-	-	-
28 PLANT RELATED	(546,838)	(1,488,849)		(652,729)		(10,848)	(13,008)	(23,856)
29 RATE BASE RELATED	(2,337)	(6,367)		(2,811)		(50)	(57)	(107)
30 AVAILABLE	-	-		-		-	-	-
31 AVAILABLE	-	-		-		-	-	-
32 TOTAL DEDUCTIONS	(1,356,789)	(3,335,004)		(1,368,233)		(22,495)	(36,055)	(58,550)
33								
34 ADJUSTED INCOME	(3,404,668)	(10,312,056)		(2,665,539)		(117,163)	(240,554)	(357,716)
35								
36 LESS:								
37 SIT DEDUCTION	(107,315)	(323,676)		(85,841)		(3,628)	(7,374)	(11,002)
38 SIT DEDUCTION	-	-		-		-	-	-
39 SIT DEDUCTION	-	-		-		-	-	-

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	COMMERCIAL / SMALL INDUSTRIAL							
	LIGHT & POWER					LIGHT & POWER TOU		
	PRI	SEC	PRIMARY SUB	GENERAL SERVICE	C-1 RIDER	SEC	PRI	TOTAL
	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
40								
41 FEDERAL TAXABLE INCOME	(3,297,354)	(9,988,380)		(2,579,698)		(113,535)	(233,179)	(346,714)
42								
43 TAX AT PRESENT BEFORE CREDITS	(692,444)	(2,097,560)	-	(541,737)	-	(23,842)	(48,968)	(72,810)
44								
45 AFTER TAX PROVISIONS								
46 CURRENT SIT	(107,315)	(323,676)		(85,841)		(3,628)	(7,374)	(11,002)
47 DEFERRED SIT	(70,794)	(213,523)		(56,628)		(2,393)	(4,865)	(7,258)
48 DEFERRED FIT	230,158	605,104		261,099		4,320	5,723	10,042
49 DEFERRED - EXCESS	(183,343)	(499,179)		(218,846)		(3,637)	(4,361)	(7,998)
50 ITC	(7,343)	(19,993)		(8,765)		(146)	(175)	(320)
51								
52 INCOME TAXES CHARGED TO UTILITY	(831,081)	(2,548,827)		(650,718)		(29,327)	(60,020)	(89,347)

LOUISIANA INCOME TAX CALCULATION

	PRI (12)	SEC (13)	PRIMARY SUB (14)	GENERAL SERVICE (15)	C-1 RIDER (16)	SEC (17)	PRI (18)	TOTAL (19)
1 NET INCOME FROM LOUISIANA SOURCES	-	-		-		-	-	-
2 Deductible State Tax Expense (States other than LA)	-	-		-		-	-	-
3 INC SUBJECT TO APPORTIONMENT	-	-		-		-	-	
4 INC APPORTIONED AT PLANT	-	-		-		-	-	-
5 RENTS/ROYALTIES - LA ONLY	-	-		-		-	-	-
6 LA FEDERAL INC TAX DED	-	-		-		-	-	-
7 LOUISIANA TAXABLE INCOME	-	-		-		-	-	

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		COMMERCIAL / SMALL INDUSTRIAL							
		LIGHT & POWER			GENERAL	C-1	LIGHT & POWER TOU		
		PRI	SEC	PRIMARY SUB	SERVICE	RIDER	SEC	PRI	TOTAL
		(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
8	LA TAXES CHARGED TO UTILITY	-	-		-		-	-	
	ARKANSAS INCOME TAX CALCULATION								
1	FEDERAL TAXABLE INCOME	10,590,106	32,079,665		8,285,212		364,639	748,902	1,113,541
2									
3	PLUS:								
4	Deductible State Tax Expense (States other than AR)	(215,681)	(587,226)		(257,446)		(4,279)	(5,131)	(9,409)
5	BONUS DEPRECIATION	(15,430,462)	(46,742,126)		(12,072,085)		(531,302)	(1,091,198)	(1,622,500)
6	1999 CAPITAL LOSSES / GAINS	-	-		-		-	-	-
7									
8	INC SUBJECT TO APPORTIONMENT	(5,056,037)	(15,249,686)		(4,044,319)		(170,942)	(347,427)	(518,369)
9									
10	INC APPORTIONED AT 0.243859	(1,232,960)	(3,718,773)		(986,244)		(41,686)	(84,723)	(126,409)
11	AR TAXES CHARGED TO UTILITY	(80,142)	(241,720)	0	(64,106)	0	(2,710)	(5,507)	(8,217)
12									
13	TEXAS GROSS RECEIPTS TAX	-	-		-		-	-	-
14	OTHER STATE INCOME TAX	(27,172)	(81,956)		(21,735)		(919)	(1,867)	(2,786)
15									
16	TOTAL STATE INCOME TAXES	(107,315)	(323,676)		(85,841)		(3,628)	(7,374)	(11,002)

Supporting Schedules

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

COMMERCIAL / SMALL INDUSTRIAL							
LIGHT & POWER			GENERAL	C-1	LIGHT & POWER TOU		
PRI	SEC	PRIMARY SUB	SERVICE	RIDER	SEC	PRI	TOTAL
(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)

(a) C-1
(b) G-4
(c) H-1
(d) F-1.3
WP's G-2
WP's G-2 and G-3
G Class WP

Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas
if the amounts brought forward from supporting schedules are at the Arkai
(non-Arkansas) amounts on the supporitng schedules. The associated pl
specific plant accounts. Workpapers detailing classification/functionalizati
classified and/or allocated in a manner different from the previous rate cas

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		LARGE INDUSTRIAL				
	LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
	PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE	TOTAL
	(20)	(21)	(22)	(23)	(24)	(25)
OPERATING REVENUES						0
						0
1 FIRM SALES OF ELECTRICITY						0
2 BASE FIRM REVENUE	3,731,299	2,195,911	5,927,210	4,254,656	966,899	5,221,554
3 FIRM FUEL REVENUES	0	0	0	0	0	0
4						0
5 TOTAL FIRM SALES OF ELECTRICITY	3,731,299	2,195,911	5,927,210	4,254,656	966,899	5,221,554
6						0
7 NON-FIRM SALES						0
8 NON-FIRM REVENUE-DEMAND	0	0	0	0	0	0
9 NON-FIRM REVENUE FUEL (Capacity Revenue)	0	0	0	0	0	0
10 TOTAL NON-FIRM SALES	0	0	0	0	0	0
11						0
12 450-FORFEITED DISCOUNTS	18	9	27	9	44	53
13						0
14 451-MISCELLANEOUS SERVICE REVENUE	8	4	12	4	20	24
15						0
16 454 - RENT FROM ELECTRIC PROPERTY	52,377	203	52,580	203	15,603	15,807
17						0
18 456 - OTHER ELECTRIC REVENUES						0
19 GENERATION RELATED	32,546	19,826	52,372	33,496	4,337	37,833
20 GENERAL OFFICE RENTAL	12,418	9,052	21,471	14,665	1,830	16,495
21 TRANS RELATED REVENUE	891,508	667,785	1,559,293	1,056,152	168,410	1,224,562
22 TOTAL OTHER ELECTRIC REVENUES	936,472	696,663	1,633,135	1,104,312	174,577	1,278,889

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		LARGE INDUSTRIAL					
		LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
		PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE	TOTAL
		(20)	(21)	(22)	(23)	(24)	(25)
23							0
24	TOTAL OTHER OPERATING REVENUE	988,875	696,879	1,685,754	1,104,528	190,245	1,294,773
25							0
26	TOTAL OPERATING REVENUES	4,720,175	2,892,790	7,612,964	5,359,184	1,157,143	6,516,327
	OPERATION & MAINTENANCE EXPENSE						
1	POWER PRODUCTION EXPENSES						
2	STEAM POWER GENERATION						
3	OPERATION						
4	500-SUPERVISION & ENGINEERI NG	135,425	89,995	225,420	148,873	18,931	167,804
5	501-FUEL						
6	DIRECT ASSIGNED COMMODITY FUEL	-	-	-	-	-	-
7	DIRECT ASSIGNED OFF SYSTEM WSALE	-	-	-	-	-	-
8	DIRECT ASSIGNED RETAIL NFIRM	-	-	-	-	-	-
9	NON-ELIGIBLE	151,467	133,059	284,525	207,544	24,995	232,539
10	MINE CLOSING	-	-	-	-	-	-
11	AVAILABLE	-	-	-	-	-	-
12	TOTAL ACCOUNT 501	151,467	133,059	284,525	207,544	24,995	232,539
13	502-STEAM	115,680	70,469	186,149	119,056	15,416	134,472
14	505-ELECTRIC	45,228	27,552	72,780	46,548	6,027	52,575
15	506-MISCELLANEOUS POWER	153,935	93,773	247,708	158,427	20,514	178,941
16	507-RENTS	14	8	22	14	2	16
17	509-ALLOWANCE EXPENSE	1,909	1,163	3,072	1,965	254	2,219

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CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		LARGE INDUSTRIAL					
		LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
		PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE	TOTAL
		(20)	(21)	(22)	(23)	(24)	(25)
18	TOTAL STEAM OPERATION	603,658	416,020	1,019,678	682,427	86,139	768,567
19	MAINTENANCE			-			-
20	510-SUPERVISION & ENGINEERING	41,005	35,054	76,059	54,960	6,653	61,613
21	511-STRUCTURES	21,060	12,829	33,889	21,675	2,807	24,481
22	512-BOILER PLANT	357,598	314,137	671,735	489,990	59,011	549,001
23	513-ELECTRIC PLANT	43,588	38,291	81,879	59,726	7,193	66,919
24	514-MISC STEAM PLANT	30,474	18,564	49,038	31,363	4,061	35,424
25	TOTAL STEAM MAINTENANCE	493,725	418,875	912,600	657,714	79,724	737,438
26	TOTAL STEAM GENERATION EXPENSE	1,097,383	834,895	1,932,278	1,340,141	165,864	1,506,005
27	POWER PRODUCTION EXPENSES-OTHER			-			-
28	OPERATION	-	-	-	-	-	-
29	546-OPERATION & SUPERVISION	-	-	-	-	-	-
30	547-FUEL	-	-	-	-	-	-
31	548-GEN EXP	4,718	2,874	7,592	4,855	629	5,484
32	549-MISCELLANEOUS OTHER POWER GEN	-	-	-	-	-	-
33	550-RENTS	-	-	-	-	-	-
34	TOTAL OTHER POWER OPERATION	4,718	2,874	7,592	4,855	629	5,484
35	MAINTENANCE			-			-
36	551-SUPERVISION & ENGINEERING	-	-	-	-	-	-
37	552-STRUCTURES	-	-	-	-	-	-
38	553-GENERAL & ELECTRIC PLANT	4,705	2,866	7,571	4,842	627	5,469
39	554-MISCELLANEOUS OTHER GEN	126	77	202	129	17	146
40	TOTAL OTHER POWER MAINTENANCE	4,830	2,943	7,773	4,971	644	5,615
41	TOTAL OTHER POWER	9,548	5,816	15,365	9,827	1,272	11,099

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CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		LARGE INDUSTRIAL					
		LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
		PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE	TOTAL
		(20)	(21)	(22)	(23)	(24)	(25)
42	OTHER GENERATION EXPENSES			-			-
43	555-PURCHASED POWER DEMAND	67,162	40,913	108,076	69,122	8,950	78,072
44	555-PURCHASED POWER ENERGY	-	-	-	-	-	-
45	555-PURCHASED POWER FUEL	-	-	-	-	-	-
46	TOTAL ACCOUNT 555	67,162	40,913	108,076	69,122	8,950	78,072
47	556-SYSTEM DISPATCHING	14,267	8,691	22,958	14,683	1,901	16,585
48	557-Fuel Related	-	-	-	-	-	-
49	557-OTHER	27,414	16,700	44,114	28,214	3,653	31,868
50	TOTAL OTHER PRODUCTION EXPENSE	108,844	66,305	175,148	112,020	14,505	126,525
51	TOTAL PRODUCTION O&M EXPENSE	1,215,775	907,016	2,122,791	1,461,988	181,641	1,643,629
				-			-
	OPERATION & MAINTENANCE EXPENSE			-			-
				-			-
1	TRANSMISSION EXPENSES			-			-
2	OPERATION			-			-
3	560-SUPERVISION & ENGR	59,472	44,548	104,020	70,456	11,235	81,690
4	561-LOAD DISPATCHING	114,760	85,961	200,721	135,954	21,679	157,632
5	562-STATION EQUIPMENT	4,300	3,221	7,521	5,094	812	5,906
6	563-OVERHEAD LINES	3,393	2,542	5,935	4,020	641	4,661
7	564-UNDERGROUND LINES	-	-	-	-	-	-
8	565-TRANSMISSION FOR OTHERS			-			-
9	OATT AFFILIATED	-	-	-	-	-	-
10	SPP FEES	845,805	633,551	1,479,356	1,002,008	159,776	1,161,785
11	3RD PARTY WHEELING	-	-	-	-	-	-

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CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		LARGE INDUSTRIAL					
		LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
		PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE	TOTAL
		(20)	(21)	(22)	(23)	(24)	(25)
12	TOTAL TRANSMISSION BY OTHERS	845,805	633,551	1,479,356	1,002,008	159,776	1,161,785
13	566-MISC TRANSMISSION	15,656	11,727	27,384	18,548	2,958	21,505
14	566-MISC TRANSMISSION SPP	-	-	-	-	-	-
15	567-RENTS	294	220	514	348	56	404
16	5757-SPP Admin-MAM&SC	12,101	9,064	21,165	14,336	2,286	16,622
17	TOTAL TRANSMISSION OPERATION	1,055,782	790,835	1,846,617	1,250,764	199,442	1,450,206
18				-			-
19	MAINTENANCE			-			-
20	568-SUPERVISION & ENGR	329	247	576	390	62	452
21	569-STRUCTURES	4,586	3,435	8,022	5,433	866	6,300
22	570-STATION EQUIPMENT	28,162	21,095	49,257	33,363	5,320	38,683
23	571-OVERHEAD LINES	82,631	61,894	144,525	97,891	15,609	113,500
24	571-OVERHEAD LINES	-	-	-	-	-	-
25	572-UNDERGROUND LINES	8	6	13	9	1	10
26	573-MISCELLANEOUS	307	230	538	364	58	422
27	TOTAL TRANSMISSION MAINTENANCE	116,023	86,907	202,930	137,450	21,917	159,367
28				-			-
29	TOTAL TRANSMISSION O&M EXP	1,171,805	877,742	2,049,547	1,388,215	221,359	1,609,573
				-			-
				-			-
	OPERATION & MAINTENANCE EXPENSE			-			-
				-			-
1	DISTRIBUTION EXPENSES			-			-
2	OPERATION			-			-

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PRODUCTION ALLOCATION METHOD
4 CP A&E

		LARGE INDUSTRIAL					
		LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
		PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE	TOTAL
		(20)	(21)	(22)	(23)	(24)	(25)
3	580-SUPERVISION & ENGR	10,395	251	10,646	252	3,252	3,504
4	581-LOAD DISPATCHING	173	1	173	1	51	52
5	582-STATION EQUIPMENT	4,308	-	4,308	-	1,270	1,270
6	583-OVERHEAD LINES	16,798	-	16,798	-	4,953	4,953
7	584-UNDERGROUND LINES	9,989	-	9,989	-	2,945	2,945
8	585-STREET LIGHTING & SIGNAL	-	-	-	-	-	-
9	586-METERS	621	1,853	2,473	1,857	1,556	3,413
10	587-CUST INSTALLATION	-	-	-	-	-	-
11	588-MISC DISTRIBUTION	105,062	407	105,469	408	31,298	31,706
12	589-RENTS	4,885	19	4,904	19	1,455	1,474
13	TOTAL DISTRIBUTION OPERATION	152,232	2,530	154,762	2,536	46,782	49,318
14				-			-
15	MAINTENANCE			-			-
16	590-SUPERVISION & ENGR	1,845	10	1,854	10	551	561
17	591-STRUCTURES	279	-	279	-	82	82
18	592-STATION EQUIPMENT	6,873	-	6,873	-	2,026	2,026
19	593-OVERHEAD LINES	133,955	-	133,955	-	39,496	39,496
20	593-OVERHEAD LINES	88,381	342	88,723	343	26,329	26,672
21	594-UNDERGROUND LINES	4,761	-	4,761	-	1,404	1,404
22	595-LINE TRANSFORMERS	820	-	820	-	242	242
23	596-STREET LIGHTING & SIGNAL	-	-	-	-	-	-
24	597-METERS	85	255	340	255	214	470
25	598-MISCELLANEOUS PLANT	-	-	-	-	-	-
26	TOTAL DISTRIBUTION MAINTENANCE	236,999	607	237,606	608	70,344	70,953

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PRODUCTION ALLOCATION METHOD
4 CP A&E

		LARGE INDUSTRIAL					
		LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
		PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE	TOTAL
		(20)	(21)	(22)	(23)	(24)	(25)
27				-			-
28	TOTAL DISTRIBUTION EXPENSES	389,231	3,137	392,368	3,144	117,126	120,270
				-			-
				-			-
	OPEF			-			-
				-			-
1	CUSTOMER ACCOUNTS EXPENSES			-			-
2	OPERATION			-			-
3	901-SUPERVISION & ENGR	2,637	1,068	3,705	2,984	3,456	6,440
4	902-METER READING	8	4	11	4	27	30
5	903-CUST ACCT & COLL-GENL	-	-	-	-	-	-
6	CUST ACCT & COLL-BILLING	76,970	31,166	108,136	87,081	100,831	187,912
7	FACTORING EXP	-	-	-	-	-	-
8	INTEREST ON CUSTOMER DEPOSITS	-	-	-	-	-	-
9	TOTAL 903	76,970	31,166	108,136	87,081	100,831	187,912
10	904-UNCOLLECTABLE	10,076	5,930	16,006	11,489	2,611	14,101
11	905-MISCELLANEOUS	410	166	576	463	537	1,000
12	TOT CUSTOMER ACCOUNTS	90,101	38,333	128,434	102,022	107,461	209,483
13				-			-
14	CUSTOMER INFORMATION			-			-
15	OPERATION			-			-
16	907-SUPERVISION	4,939	4,420	9,359	6,893	818	7,712
17	908-CUSTOMER ASSISTANCE			-			-
18	CUSTOMER ASSISTANCE	17,125	15,324	32,449	23,900	2,838	26,738

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		LARGE INDUSTRIAL					
		LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
		PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE	TOTAL
		(20)	(21)	(22)	(23)	(24)	(25)
19	ENERY EFFIC INCENTIVE AMORT	-	-	-	-	-	-
20	TOTAL ACCOUNT 908	17,125	15,324	32,449	23,900	2,838	26,738
21	909-INFO & INSTRUCTION	71	64	135	99	12	111
22	910-MISC CUSTOMER SERVICE	42	38	80	59	7	66
23	TOT CUSTOMER INFO	22,177	19,844	42,021	30,951	3,675	34,626
24				-			-
25	CONSUMER SERVICES			-			-
26	OPERATION			-			-
27	911-SUPERVISION	2	1	3	2	0	2
28	912-DEMO & SELLING	817	731	1,548	1,140	135	1,276
29	913-ADVERTISING	(110)	(99)	(209)	(154)	(18)	(172)
30	916-MISC SALES EXP	-	-	-	-	-	-
31	TOT CONSUMER SVCS	709	634	1,342	989	117	1,106
32				-			-
33	ADMINISTRATIVE & GENERAL EXP			-			-
34	920-ADMINISTRATIVE AND GENERAL	222,793	130,403	353,195	216,245	56,583	272,828
35	921-OFFICE SUPPLIES AND EXPNESES	16,221	9,494	25,716	15,745	4,120	19,864
36	922-ADMIN EXPENSE TRANSFERRED	(23,918)	(14,000)	(37,918)	(23,215)	(6,075)	(29,290)
37	923-OUTSIDE SERVICES	114,523	67,031	181,554	111,157	29,086	140,243
38	924-PROPERTY INSURANCE	14,889	7,665	22,554	12,547	2,813	15,360
39	925-INJURIES AND DAMAGES	28,024	16,403	44,427	27,201	7,117	34,318
40	926-EMPLOYEE PENSION AND BENEFITS	64,841	37,952	102,793	62,935	16,468	79,403
41	928-REGULATORY COMMISSION EXPENSE - Ark	-	-	-	-	-	-
42	928-REGULATORY COMMISSION EXPENSE - La	-	-	-	-	-	-

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		LARGE INDUSTRIAL					
		LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
		PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE	TOTAL
		(20)	(21)	(22)	(23)	(24)	(25)
43	928-REGULATORY COMMISSION EXPENSE - Tx	-	-	-	-	-	-
44	928-REGULATORY COMMISSION EXPENSE - FERC	-	-	-	-	-	-
45	928-REGULATORY COMMISSION EXPENSE	-	-	-	-	-	-
46	9301-GENERAL ADVERTISING EXPENSE	1,858	1,092	2,950	1,810	470	2,280
47	9302-MISCELLANEOUS GENERAL EXPENSE	10,899	6,379	17,278	10,579	2,768	13,347
48	931-RENTS	7,364	5,368	12,732	8,696	1,085	9,782
49	935-MAINTENANCE OF GENERAL PLANT	51,502	37,544	89,046	60,819	7,591	68,410
50		-	-	-	-	-	-
51	TOT ADMIN & GEN EXP	508,996	305,333	814,328	504,519	122,027	626,545
52				-			-
53	TOTAL OPERATION & MAINT EXP	3,398,793	2,152,039	5,550,832	3,491,827	753,406	4,245,233
1	DEPRECIATION EXPENSE - ACCT 403						
2	PRODUCTION PLANT	684,779	417,149	1,101,928	704,763	91,255	796,017
3	TRANSMISSION PLANT	375,055	280,935	655,990	444,320	70,849	515,170
4	DISTRIBUTION PLANT	380,712	1,474	382,186	1,478	113,414	114,892
5	GENERAL PLANT	42,252	30,801	73,053	49,896	6,228	56,123
6	SUBTOTAL DEPRECIATION EXPENSE	1,482,797	730,360	2,213,157	1,200,456	281,746	1,482,202
7							
8	AMORTIZATION EXPENSE						
9	404-INTANGIBLE PLANT	129,673	75,899	205,572	125,862	32,933	158,795
10	406-PLANT ACQ ADJUSTMENT	-	-	-	-	-	-

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		LARGE INDUSTRIAL					
		LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
		PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE	TOTAL
		(20)	(21)	(22)	(23)	(24)	(25)
11	4073-Amortization Exp Ark	15,669	9,222	24,891	17,867	4,060	21,927
12	4073-Amortization Exp La	-	-	-	-	-	-
13	4073-Amortization Exp Tx	-	-	-	-	-	-
14	4073-Amortization Exp Tx	-	-	-	-	-	-
15	Accretion	17,737	8,736	26,473	14,359	3,370	17,730
16	SUBTOTAL AMORTIZATION	163,079	93,857	256,935	158,089	40,364	198,452
17							
18	TOTAL DEPRECIATION & AMORT EXP	1,645,876	824,216	2,470,092	1,358,545	322,109	1,680,654
19							
20	SO2 ALLOWANCE	4,595	2,799	7,394	4,729	612	5,341
21							
22	TAXES OTHER THAN INCOME TAX						
23	NON REVENUE RELATED TAXES						
24							
25	PAYROLL RELATED TAXES	49,403	28,916	78,319	47,951	12,547	60,498
26	PLANT RELATED TAXES	437,047	225,004	662,051	368,305	82,576	450,881
27	STATE FRANCHISE (DEL, NE, OK)	226	114	340	186	45	231
28							
29	TOTAL NON-REV RELATED TAX	486,676	254,035	740,711	416,442	95,168	511,610
1	REVENUE RELATED TAXES						
2	REVENUE RELATED TAXES ARK	16,617	9,779	26,396	18,948	4,306	23,254

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		LARGE INDUSTRIAL					
		LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
		PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE	TOTAL
		(20)	(21)	(22)	(23)	(24)	(25)
3	REVENUE RELATED TAXES LA	-	-	-	-	-	-
4	REVENUE RELATED TAXES TX	-	-	-	-	-	-
5							
6	TOTAL REVENUE-RELATED TAX	16,617	9,779	26,396	18,948	4,306	23,254
7							
8	TOT TAX OTHER THAN INCOME	503,293	263,814	767,107	435,390	99,474	534,864
WOR							
	FEDERAL INCOME TAX CALCULATION - PRESENT						
1	TOTAL REVENUES	4,720,175	2,892,790	7,612,964	5,359,184	1,157,143	6,516,327
2	LESS: EXPENSES						
3	TOTAL OPER & MAINT EXPENSE	3,403,388	2,154,838	5,558,226	3,496,556	754,018	4,250,575
4	TOTAL DEPRECIATION EXPENSE	1,645,876	824,216	2,470,092	1,358,545	322,109	1,680,654
5	TOT TAX OTHER THAN INCOME	503,293	263,814	767,107	435,390	99,474	534,864
6	TOTAL EXPENSES	5,552,557	3,242,868	8,795,425	5,290,491	1,175,602	6,466,093
7	OPERATING INCOME BEFORE TAXES	(832,383)	(350,078)	(1,182,461)	68,693	(18,459)	50,234
8							
9	LESS: INTEREST	663,691	335,575	999,266	545,789	132,059	677,849
10							
11	PLUS: SCHEDULE M DIFFERENCES						
12	PERMANENT						
13	DEPRECIATION EXP RELATED	42,168	20,770	62,937	34,138	8,012	42,151
14	ENERGY RELATED	(121,870)	(107,058)	(228,928)	(166,989)	(20,111)	(187,100)
15	TOTAL PAYROLL RELATED	2,750	1,609	4,359	2,669	698	3,367

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		LARGE INDUSTRIAL					
		LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
		PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE	TOTAL
		(20)	(21)	(22)	(23)	(24)	(25)
16	PLANT RELATED	-	-	-	-	-	-
17	INTANGIBLE PLANT RELATED	-	-	-	-	-	-
18	TEMPORARY						
19	RETAIL CUSTOMER RELATED	-	-	-	-	-	-
20	RETAIL PROD DEMAND RELATED	-	-	-	-	-	-
21	DEPRECIATION EXP RELATED	(149,944)	(73,856)	(223,800)	(121,393)	(28,491)	(149,884)
22	DISTRIBUTION PLANT RELATED	13,059	51	13,110	51	3,890	3,941
23	ENERGY RELATED	(42,123)	(37,004)	(79,127)	(57,718)	(6,951)	(64,670)
24	FUEL RELATED	-	-	-	-	-	-
25	INTANGIBLE PLANT RELATED	-	-	-	-	-	-
26	TOTAL PAYROLL RELATED	(17,000)	(9,950)	(26,950)	(16,500)	(4,318)	(20,818)
27	MINE RECLAMATION	-	-	-	-	-	-
28	PLANT RELATED	(201,979)	(103,985)	(305,964)	(170,210)	(38,162)	(208,373)
29	RATE BASE RELATED	(858)	(434)	(1,293)	(706)	(171)	(877)
30	AVAILABLE	-	-	-	-	-	-
31	AVAILABLE	-	-	-	-	-	-
32	TOTAL DEDUCTIONS	(475,798)	(309,857)	(785,656)	(496,659)	(85,603)	(582,262)
33							
34	ADJUSTED INCOME	(1,971,872)	(995,510)	(2,967,382)	(973,756)	(236,121)	(1,209,877)
35							
36	LESS:						
37	SIT DEDUCTION	(61,222)	(30,924)	(92,146)	(30,805)	(7,444)	(38,249)
38	SIT DEDUCTION	-	-	-	-	-	-
39	SIT DEDUCTION	-	-	-	-	-	-

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Schedule: G-3
Cost of Service Study - Revenue and Expense Detail
Class

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		LARGE INDUSTRIAL					
		LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
		PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE	TOTAL
		(20)	(21)	(22)	(23)	(24)	(25)
40							
41	FEDERAL TAXABLE INCOME	(1,910,650)	(964,586)	(2,875,236)	(942,951)	(228,677)	(1,171,627)
42							
43	TAX AT PRESENT BEFORE CREDITS	(401,237)	(202,563)	(603,800)	(198,020)	(48,022)	(246,042)
44							
45	AFTER TAX PROVISIONS						
46	CURRENT SIT	(61,222)	(30,924)	(92,146)	(30,805)	(7,444)	(38,249)
47	DEFERRED SIT	(40,387)	(20,400)	(60,787)	(20,321)	(4,911)	(25,232)
48	DEFERRED FIT	83,758	47,287	131,045	76,960	15,582	92,543
49	DEFERRED - EXCESS	(67,719)	(34,864)	(102,583)	(57,068)	(12,795)	(69,863)
50	ITC	(2,712)	(1,396)	(4,109)	(2,286)	(512)	(2,798)
51							
52	INCOME TAXES CHARGED TO UTILITY	(489,519)	(242,861)	(732,380)	(231,539)	(58,102)	(289,642)
	LOUISIANA INCOME TAX CALCULATION						
1	NET INCOME FROM LOUISIANA SOURCES	-	-	-	-	-	-
2	Deductible State Tax Expense (States other than LA)	-	-	-	-	-	-
3	INC SUBJECT TO APPORTIONMENT	-	-		-	-	
4	INC APPORTIONED AT PLANT	-	-	-	-	-	-
5	RENTS/ROYALTIES - LA ONLY	-	-	-	-	-	-
6	LA FEDERAL INC TAX DED	-	-	-	-	-	-
7	LOUISIANA TAXABLE INCOME	-	-		-	-	

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		LARGE INDUSTRIAL					
		LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
		PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE	TOTAL
		(20)	(21)	(22)	(23)	(24)	(25)
8	LA TAXES CHARGED TO UTILITY	-	-		-	-	
	ARKANSAS INCOME TAX CALCULATION						
1	FEDERAL TAXABLE INCOME	6,136,433	3,097,958	9,234,391	3,028,473	734,440	3,762,914
2							
3	PLUS:						
4	Deductible State Tax Expense (States other than AR)	(79,664)	(41,013)	(120,677)	(67,134)	(15,052)	(82,185)
5	BONUS DEPRECIATION	(8,941,175)	(4,513,923)	(13,455,098)	(4,412,680)	(1,070,127)	(5,482,806)
6	1999 CAPITAL LOSSES / GAINS	-	-	-	-	-	-
7							
8	INC SUBJECT TO APPORTIONMENT	(2,884,406)	(1,456,978)	(4,341,385)	(1,451,340)	(350,738)	(1,802,078)
9							
10	INC APPORTIONED AT 0.243859	(703,388)	(355,297)	(1,058,686)	(353,922)	(85,531)	(439,453)
11	AR TAXES CHARGED TO UTILITY	(45,720)	(23,094)	(68,815)	(23,005)	(5,559)	(28,564)
12							
13	TEXAS GROSS RECEIPTS TAX	-	-	-	-	-	-
14	OTHER STATE INCOME TAX	(15,502)	(7,830)	(23,332)	(7,800)	(1,885)	(9,685)
15							
16	TOTAL STATE INCOME TAXES	(61,222)	(30,924)	(92,146)	(30,805)	(7,444)	(38,249)

Supporting Schedules

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

LARGE INDUSTRIAL					
LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE	TOTAL
(20)	(21)	(22)	(23)	(24)	(25)

(a) C-1
(b) G-4
(c) H-1
(d) F-1.3
WP's G-2
WP's G-2 and G-3
G Class WP

Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas
if the amounts brought forward from supporting schedules are at the Arkai
(non-Arkansas) amounts on the supporitng schedules. The associated pl
specific plant accounts. Workpapers detailing classification/functionalizati
classified and/or allocated in a manner different from the previous rate cas

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		MUNICIPAL		LIGHTING			
		PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
	OPERATING REVENUES						0
							0
1	FIRM SALES OF ELECTRICITY						0
2	BASE FIRM REVENUE	509,010	244,646	1,388,614		3,169,707	4,558,322
3	FIRM FUEL REVENUES	0	0	0		0	0
4							0
5	TOTAL FIRM SALES OF ELECTRICITY	509,010	244,646	1,388,614		3,169,707	4,558,322
6							0
7	NON-FIRM SALES						0
8	NON-FIRM REVENUE-DEMAND	0	0	0		0	0
9	NON-FIRM REVENUE FUEL (Capacity Revenue)	0	0	0		0	0
10	TOTAL NON-FIRM SALES	0	0	0		0	0
11							0
12	450-FORFEITED DISCOUNTS	2,407	4,279	126,256		146,021	272,277
13							0
14	451-MISCELLANEOUS SERVICE REVENUE	1,077	1,914	56,474		65,315	121,790
15							0
16	454 - RENT FROM ELECTRIC PROPERTY	8,012	3,351	38,431		50,951	89,382
17							0
18	456 - OTHER ELECTRIC REVENUES						0
19	GENERATION RELATED	2,505	1,092	1,377		3,150	4,527
20	GENERAL OFFICE RENTAL	1,039	417	668		1,534	2,202
21	TRANS RELATED REVENUE	76,912	32,322	1,368		3,204	4,572
22	TOTAL OTHER ELECTRIC REVENUES	80,456	33,831	3,413		7,888	11,301

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		MUNICIPAL		LIGHTING			
		PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
23							0
24	TOTAL OTHER OPERATING REVENUE	91,952	43,376	224,575		270,174	494,750
25							0
26	TOTAL OPERATING REVENUES	600,962	288,022	1,613,190		3,439,882	5,053,071
	OPERATION & MAINTENANCE EXPENSE						
1	POWER PRODUCTION EXPENSES						
2	STEAM POWER GENERATION						
3	OPERATION						
4	500-SUPERVISION & ENGINEERI NG	10,843	4,546	6,450		14,780	21,230
5	501-FUEL						
6	DIRECT ASSIGNED COMMODITY FUEL	-	-	-		-	-
7	DIRECT ASSIGNED OFF SYSTEM WSALE	-	-	-		-	-
8	DIRECT ASSIGNED RETAIL NFIRM	-	-	-		-	-
9	NON-ELIGIBLE	13,944	5,093	10,329		23,753	34,082
10	MINE CLOSING	-	-	-		-	-
11	AVAILABLE	-	-	-		-	-
12	TOTAL ACCOUNT 501	13,944	5,093	10,329		23,753	34,082
13	502-STEAM	8,903	3,882	4,894		11,197	16,092
14	505-ELECTRIC	3,481	1,518	1,913		4,378	6,291
15	506-MISCELLANEOUS POWER	11,848	5,166	6,513		14,900	21,413
16	507-RENTS	1	0	1		1	2
17	509-ALLOWANCE EXPENSE	147	64	81		185	266

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		MUNICIPAL		LIGHTING			
		PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
18	TOTAL STEAM OPERATION	49,167	20,270	30,181		69,194	99,375
19	MAINTENANCE						-
20	510-SUPERVISION & ENGINEERING	3,721	1,379	2,703		6,215	8,918
21	511-STRUCTURES	1,621	707	891		2,039	2,930
22	512-BOILER PLANT	32,920	12,025	24,386		56,077	80,464
23	513-ELECTRIC PLANT	4,013	1,466	2,972		6,835	9,808
24	514-MISC STEAM PLANT	2,345	1,023	1,289		2,950	4,239
25	TOTAL STEAM MAINTENANCE	44,620	16,599	32,242		74,116	106,358
26	TOTAL STEAM GENERATION EXPENSE	93,787	36,869	62,424		143,310	205,733
27	POWER PRODUCTION EXPENSES-OTHER						-
28	OPERATION	-	-	-		-	-
29	546-OPERATION & SUPERVISION	-	-	-		-	-
30	547-FUEL	-	-	-		-	-
31	548-GEN EXP	363	158	200		457	656
32	549-MISCELLANEOUS OTHER POWER GEN	-	-	-		-	-
33	550-RENTS	-	-	-		-	-
34	TOTAL OTHER POWER OPERATION	363	158	200		457	656
35	MAINTENANCE						-
36	551-SUPERVISION & ENGINEERING	-	-	-		-	-
37	552-STRUCTURES	-	-	-		-	-
38	553-GENERAL & ELECTRIC PLANT	362	158	199		455	654
39	554-MISCELLANEOUS OTHER GEN	10	4	5		12	18
40	TOTAL OTHER POWER MAINTENANCE	372	162	204		468	672
41	TOTAL OTHER POWER	735	320	404		924	1,328

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		MUNICIPAL		LIGHTING			
		PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
42	OTHER GENERATION EXPENSES						-
43	555-PURCHASED POWER DEMAND	5,169	2,254	2,841		6,501	9,342
44	555-PURCHASED POWER ENERGY	-	-	-		-	-
45	555-PURCHASED POWER FUEL	-	-	-		-	-
46	TOTAL ACCOUNT 555	5,169	2,254	2,841		6,501	9,342
47	556-SYSTEM DISPATCHING	1,098	479	604		1,381	1,985
48	557-Fuel Related	-	-	-		-	-
49	557-OTHER	2,110	920	1,160		2,654	3,813
50	TOTAL OTHER PRODUCTION EXPENSE	8,377	3,653	4,605		10,536	15,141
51	TOTAL PRODUCTION O&M EXPENSE	102,899	40,842	67,432		154,770	222,202
							-
	OPERATION & MAINTENANCE EXPENSE						-
							-
1	TRANSMISSION EXPENSES						-
2	OPERATION						-
3	560-SUPERVISION & ENGR	5,131	2,156	91		214	305
4	561-LOAD DISPATCHING	9,900	4,161	176		412	589
5	562-STATION EQUIPMENT	371	156	7		15	22
6	563-OVERHEAD LINES	293	123	5		12	17
7	564-UNDERGROUND LINES	-	-	-		-	-
8	565-TRANSMISSION FOR OTHERS						-
9	OATT AFFILIATED	-	-	-		-	-
10	SPP FEES	72,969	30,665	1,298		3,040	4,338
11	3RD PARTY WHEELING	-	-	-		-	-

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		MUNICIPAL		LIGHTING			
		PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
12	TOTAL TRANSMISSION BY OTHERS	72,969	30,665	1,298		3,040	4,338
13	566-MISC TRANSMISSION	1,351	568	24		56	80
14	566-MISC TRANSMISSION SPP	-	-	-		-	-
15	567-RENTS	25	11	0		1	2
16	5757-SPP Admin-MAM&SC	1,044	439	19		43	62
17	TOTAL TRANSMISSION OPERATION	91,084	38,278	1,620		3,794	5,415
18							-
19	MAINTENANCE						-
20	568-SUPERVISION & ENGR	28	12	1		1	2
21	569-STRUCTURES	396	166	7		16	24
22	570-STATION EQUIPMENT	2,430	1,021	43		101	144
23	571-OVERHEAD LINES	7,129	2,996	127		297	424
24	571-OVERHEAD LINES	-	-	-		-	-
25	572-UNDERGROUND LINES	1	0	0		0	0
26	573-MISCELLANEOUS	27	11	0		1	2
27	TOTAL TRANSMISSION MAINTENANCE	10,009	4,206	178		417	595
28							-
29	TOTAL TRANSMISSION O&M EXP	101,093	42,484	1,798		4,211	6,010
							-
							-
	OPERATION & MAINTENANCE EXPENSE						-
							-
1	DISTRIBUTION EXPENSES						-
2	OPERATION						-

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		MUNICIPAL		LIGHTING			
		PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
3	580-SUPERVISION & ENGR	1,963	1,180	8,246		20,578	28,824
4	581-LOAD DISPATCHING	26	11	127		168	295
5	582-STATION EQUIPMENT	436	149	442		983	1,425
6	583-OVERHEAD LINES	2,700	925	2,734		6,087	8,821
7	584-UNDERGROUND LINES	2,358	808	2,388		5,318	7,706
8	585-STREET LIGHTING & SIGNAL	-	-	33,345		-	33,345
9	586-METERS	2,573	4,380	-		-	-
10	587-CUST INSTALLATION	-	-	-		126,372	126,372
11	588-MISC DISTRIBUTION	16,072	6,722	77,088		102,201	179,289
12	589-RENTS	747	313	3,584		4,752	8,336
13	TOTAL DISTRIBUTION OPERATION	26,876	14,488	127,954		266,459	394,413
14							-
15	MAINTENANCE						-
16	590-SUPERVISION & ENGR	309	124	2,230		1,970	4,199
17	591-STRUCTURES	28	10	29		64	92
18	592-STATION EQUIPMENT	696	238	705		1,569	2,273
19	593-OVERHEAD LINES	21,528	7,373	21,802		48,543	70,345
20	593-OVERHEAD LINES	13,520	5,655	64,849		85,973	150,822
21	594-UNDERGROUND LINES	1,124	385	1,138		2,534	3,673
22	595-LINE TRANSFORMERS	83	28	84		187	271
23	596-STREET LIGHTING & SIGNAL	-	-	64,412		-	64,412
24	597-METERS	354	603	-		-	-
25	598-MISCELLANEOUS PLANT	-	-	-		43,021	43,021
26	TOTAL DISTRIBUTION MAINTENANCE	37,642	14,416	155,248		183,861	339,109

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		MUNICIPAL		LIGHTING			
		PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
27							-
28	TOTAL DISTRIBUTION EXPENSES	64,518	28,904	283,202		450,320	733,522
							-
							-
	OPEF						-
							-
1	CUSTOMER ACCOUNTS EXPENSES						-
2	OPERATION						-
3	901-SUPERVISION & ENGR	333	592	191		-	191
4	902-METER READING	1,385	2,462	-		-	-
5	903-CUST ACCT & COLL-GENL	-	-	-		-	-
6	CUST ACCT & COLL-BILLING	7,735	13,751	5,585		-	5,585
7	FACTORING EXP	-	-	-		-	-
8	INTEREST ON CUSTOMER DEPOSITS	-	-	-		-	-
9	TOTAL 903	7,735	13,751	5,585		-	5,585
10	904-UNCOLLECTABLE	1,375	661	3,750		8,560	12,310
11	905-MISCELLANEOUS	52	92	30		-	30
12	TOT CUSTOMER ACCOUNTS	10,880	17,558	9,556		8,560	18,115
13							-
14	CUSTOMER INFORMATION						-
15	OPERATION						-
16	907-SUPERVISION	640	512	10,663		12,707	23,370
17	908-CUSTOMER ASSISTANCE						-
18	CUSTOMER ASSISTANCE	2,218	1,775	36,971		44,057	81,028

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

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PRODUCTION ALLOCATION METHOD
4 CP A&E

		MUNICIPAL		LIGHTING			
		PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
19	ENERY EFFIC INCENTIVE AMORT	-	-	-		-	-
20	TOTAL ACCOUNT 908	2,218	1,775	36,971		44,057	81,028
21	909-INFO & INSTRUCTION	9	7	153		183	336
22	910-MISC CUSTOMER SERVICE	5	4	91		108	199
23	TOT CUSTOMER INFO	2,872	2,299	47,878		57,055	104,933
24							-
25	CONSUMER SERVICES						-
26	OPERATION						-
27	911-SUPERVISION	0	0	3		4	7
28	912-DEMO & SELLING	106	85	1,764		2,102	3,866
29	913-ADVERTISING	(14)	(11)	(238)		(283)	(521)
30	916-MISC SALES EXP	-	-	-		-	-
31	TOT CONSUMER SVCS	92	73	1,530		1,823	3,352
32							-
33	ADMINISTRATIVE & GENERAL EXP						-
34	920-ADMINISTRATIVE AND GENERAL	23,530	13,070	66,518		108,016	174,535
35	921-OFFICE SUPPLIES AND EXPNESES	1,713	952	4,843		7,865	12,708
36	922-ADMIN EXPENSE TRANSFERRED	(2,526)	(1,403)	(7,141)		(11,596)	(18,737)
37	923-OUTSIDE SERVICES	12,095	6,718	34,193		55,524	89,717
38	924-PROPERTY INSURANCE	1,458	618	2,893		4,175	7,068
39	925-INJURIES AND DAMAGES	2,960	1,644	8,367		13,587	21,954
40	926-EMPLOYEE PENSION AND BENEFITS	6,848	3,804	19,359		31,437	50,796
41	928-REGULATORY COMMISSION EXPENSE - Ark	-	-	-		-	-
42	928-REGULATORY COMMISSION EXPENSE - La	-	-	-		-	-

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		MUNICIPAL		LIGHTING			
		PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
43	928-REGULATORY COMMISSION EXPENSE - Tx	-	-	-		-	-
44	928-REGULATORY COMMISSION EXPENSE - FERC	-	-	-		-	-
45	928-REGULATORY COMMISSION EXPENSE	-	-	-		-	-
46	9301-GENERAL ADVERTISING EXPENSE	197	111	548		890	1,437
47	9302-MISCELLANEOUS GENERAL EXPENSE	1,151	639	3,254		5,284	8,538
48	931-RENTS	616	247	396		909	1,306
49	935-MAINTENANCE OF GENERAL PLANT	4,310	1,730	2,772		6,360	9,133
50		-	-	-		-	-
51	TOT ADMIN & GEN EXP	52,353	28,130	136,002		222,451	358,453
52							-
53	TOTAL OPERATION & MAINT EXP	334,706	160,290	547,398		899,189	1,446,587
1	DEPRECIATION EXPENSE - ACCT 403						
2	PRODUCTION PLANT	52,704	22,980	28,971		66,284	95,255
3	TRANSMISSION PLANT	32,356	13,598	576		1,348	1,923
4	DISTRIBUTION PLANT	58,239	24,360	279,343		370,341	649,684
5	GENERAL PLANT	3,536	1,419	2,274		5,218	7,492
6	SUBTOTAL DEPRECIATION EXPENSE	146,835	62,356	311,164		443,191	754,355
7							
8	AMORTIZATION EXPENSE						
9	404-INTANGIBLE PLANT	13,695	7,607	38,716		62,869	101,585
10	406-PLANT ACQ ADJUSTMENT	-	-	-		-	-

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PRODUCTION ALLOCATION METHOD
4 CP A&E

		MUNICIPAL		LIGHTING			
		PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
11	4073-Amortization Exp Ark	2,138	1,027	5,831		13,311	19,142
12	4073-Amortization Exp La	-	-	-		-	-
13	4073-Amortization Exp Tx	-	-	-		-	-
14	4073-Amortization Exp Tx	-	-	-		-	-
15	Accretion	1,756	746	3,722		5,301	9,023
16	SUBTOTAL AMORTIZATION	17,589	9,380	48,269		81,482	129,751
17							
18	TOTAL DEPRECIATION & AMORT EXP	164,425	71,737	359,433		524,672	884,106
19							
20	SO2 ALLOWANCE	354	154	194		445	639
21							
22	TAXES OTHER THAN INCOME TAX						
23	NON REVENUE RELATED TAXES						
24							
25	PAYROLL RELATED TAXES	5,218	2,898	14,750		23,952	38,702
26	PLANT RELATED TAXES	42,799	18,128	84,918		122,544	207,462
27	STATE FRANCHISE (DEL, NE, OK)	23	10	49		70	120
28							
29	TOTAL NON-REV RELATED TAX	48,039	21,035	99,717		146,566	246,284
1	REVENUE RELATED TAXES						
2	REVENUE RELATED TAXES ARK	2,267	1,090	6,184		14,116	20,300

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Schedule: G-3
Cost of Service Study - Revenue and Expense Detail
Class

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

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PRODUCTION ALLOCATION METHOD
4 CP A&E

	MUNICIPAL		LIGHTING			
	PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
3 REVENUE RELATED TAXES LA	-	-	-		-	-
4 REVENUE RELATED TAXES TX	-	-	-		-	-
5						
6 TOTAL REVENUE-RELATED TAX	2,267	1,090	6,184		14,116	20,300
7						
8 TOT TAX OTHER THAN INCOME	50,306	22,125	105,902		160,682	266,584
WOR						
FEDERAL INCOME TAX CALCULATION - PRESENT						
1 TOTAL REVENUES	600,962	288,022	1,613,190		3,439,882	5,053,071
2 LESS: EXPENSES						
3 TOTAL OPER & MAINT EXPENSE	335,059	160,444	547,592		899,634	1,447,226
4 TOTAL DEPRECIATION EXPENSE	164,425	71,737	359,433		524,672	884,106
5 TOT TAX OTHER THAN INCOME	50,306	22,125	105,902		160,682	266,584
6 TOTAL EXPENSES	549,790	254,306	1,012,927		1,584,989	2,597,916
7 OPERATING INCOME BEFORE TAXES	51,172	33,716	600,263		1,854,893	2,455,156
8						
9 LESS: INTEREST	67,188	28,568	144,822		206,240	351,062
10						
11 PLUS: SCHEDULE M DIFFERENCES						
12 PERMANENT						
13 DEPRECIATION EXP RELATED	4,176	1,773	8,849		12,603	21,452
14 ENERGY RELATED	(11,219)	(4,098)	(8,311)		(19,111)	(27,422)
15 TOTAL PAYROLL RELATED	290	161	821		1,333	2,154

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		MUNICIPAL		LIGHTING			
		PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
16	PLANT RELATED	-	-	-		-	-
17	INTANGIBLE PLANT RELATED	-	-	-		-	-
18	TEMPORARY						
19	RETAIL CUSTOMER RELATED	-	-	-		-	-
20	RETAIL PROD DEMAND RELATED	-	-	-		-	-
21	DEPRECIATION EXP RELATED	(14,848)	(6,306)	(31,466)		(44,817)	(76,282)
22	DISTRIBUTION PLANT RELATED	1,998	836	9,582		12,703	22,285
23	ENERGY RELATED	(3,878)	(1,416)	(2,873)		(6,606)	(9,478)
24	FUEL RELATED	-	-	-		-	-
25	INTANGIBLE PLANT RELATED	-	-	-		-	-
26	TOTAL PAYROLL RELATED	(1,795)	(997)	(5,076)		(8,242)	(13,318)
27	MINE RECLAMATION	-	-	-		-	-
28	PLANT RELATED	(19,779)	(8,378)	(39,244)		(56,633)	(95,878)
29	RATE BASE RELATED	(87)	(37)	(187)		(267)	(454)
30	AVAILABLE	-	-	-		-	-
31	AVAILABLE	-	-	-		-	-
32	TOTAL DEDUCTIONS	(45,143)	(18,462)	(67,905)		(109,036)	(176,941)
33							
34	ADJUSTED INCOME	(61,159)	(13,313)	387,536		1,539,618	1,927,153
35							
36	LESS:						
37	SIT DEDUCTION	(2,009)	(470)	11,391		46,061	57,452
38	SIT DEDUCTION	-	-	-		-	-
39	SIT DEDUCTION	-	-	-		-	-

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		MUNICIPAL		LIGHTING			
		PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
40							
41	FEDERAL TAXABLE INCOME	(59,151)	(12,843)	376,145		1,493,556	1,869,701
42							
43	TAX AT PRESENT BEFORE CREDITS	(12,422)	(2,697)	78,990	-	313,647	392,637
44							
45	AFTER TAX PROVISIONS						
46	CURRENT SIT	(2,009)	(470)	11,391		46,061	57,452
47	DEFERRED SIT	(1,325)	(310)	7,515		30,386	37,900
48	DEFERRED FIT	8,062	3,423	14,545		21,811	36,356
49	DEFERRED - EXCESS	(6,632)	(2,809)	(13,158)		(18,988)	(32,146)
50	ITC	(266)	(112)	(527)		(760)	(1,287)
51							
52	INCOME TAXES CHARGED TO UTILITY	(14,590)	(2,976)	98,757		392,156	490,913

LOUISIANA INCOME TAX CALCULATION

1	NET INCOME FROM LOUISIANA SOURCES	-	-	-		-	-
2	Deductible State Tax Expense (States other than LA)	-	-	-		-	-
3	INC SUBJECT TO APPORTIONMENT	-	-	-		-	
4	INC APPORTIONED AT PLANT	-	-	-		-	-
5	RENTS/ROYALTIES - LA ONLY	-	-	-		-	-
6	LA FEDERAL INC TAX DED	-	-	-		-	-
7	LOUISIANA TAXABLE INCOME	-	-	-		-	

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		MUNICIPAL		LIGHTING			
		PUMPING SERVICE	MUNICIPAL SERVICE	MUNI/PUBLIC LIGHTING	PUBLIC HIGHWAY	PRIVATEAREA LIGHTING	TOTAL
		(26)	(27)	(28)	(29)	(30)	(31)
8	LA TAXES CHARGED TO UTILITY	-	-	-		-	
	ARKANSAS INCOME TAX CALCULATION						
1	FEDERAL TAXABLE INCOME	189,974	41,248	(1,208,063)		(4,796,853)	(6,004,916)
2							
3	PLUS:						
4	Deductible State Tax Expense (States other than AR)	(7,801)	(3,304)	(15,479)		(22,337)	(37,816)
5	BONUS DEPRECIATION	(276,805)	(60,101)	1,760,225		6,989,321	8,749,546
6	1999 CAPITAL LOSSES / GAINS	-	-	-		-	-
7							
8	INC SUBJECT TO APPORTIONMENT	(94,632)	(22,157)	536,683		2,170,132	2,706,815
9							
10	INC APPORTIONED AT 0.243859	(23,077)	(5,403)	130,875		529,206	660,081
11	AR TAXES CHARGED TO UTILITY	(1,500)	(351)	8,507	0	34,398	42,905
12							
13	TEXAS GROSS RECEIPTS TAX	-	-	-		-	-
14	OTHER STATE INCOME TAX	(509)	(119)	2,884		11,663	14,547
15							
16	TOTAL STATE INCOME TAXES	(2,009)	(470)	11,391		46,061	57,452

Supporting Schedules

Explanation: Schedule showing pro form year revenues and allocation of functional expenses by account, and where applicable by subaccount, to Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas Rate Schedule or Classes. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting any non-jurisdictional (non-Arkansas) amounts on the supporting schedules. The associated plant account(s) should be provided for all expenses which follow specific plant accounts. Workpapers detailing classificatoin/functioinalization by account should be provided. Identify accounts that have been classified and/or allocated in a manner differenct from the previous rate case and explain the basis for the change.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

MUNICIPAL		LIGHTING			
PUMPING SERVICE	MUNICIPAL SERVICE	MUNI/PUBLIC LIGHTING	PUBLIC HIGHWAY	PRIVATEAREA LIGHTING	TOTAL
(26)	(27)	(28)	(29)	(30)	(31)

(a) C-1
(b) G-4
(c) H-1
(d) F-1.3
WP's G-2
WP's G-2 and G-3
G Class WP

Total Company, Other Jurisdictions, Total Arkansas Retail, and Arkansas
if the amounts brought forward from supporting schedules are at the Arkai
(non-Arkansas) amounts on the supporitng schedules. The associated pl
specific plant accounts. Workpapers detailing classification/functionalizati
classified and/or allocated in a manner different from the previous rate cas

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non- Arkansas) amounts on the the supporting schedules.

JURISDICTIONAL

		ALLOC	TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)
	ALLOCATION FACTOR TABLE				
	CAPACITY RELATED				

1	PRODUCTION ALLOCATOR	DEMPROD	4,007	779	3,228
2					
3	TRANSMISSION FUNCTION	DEMTRANS	3,049	622	2,428
4	D. A. ACCT 360 - LAND	DEM360DA	11,438,936	2,769,600	8,669,336
5	D. A. ACCT 361 - STRUCTURES & IMPROVE	DEM361DA	8,435,022	2,518,993	5,916,029
6	D. A. ACCT 362 - STATION EQUIPMENT	DEM362DA	333,491,452	80,952,717	252,538,736
7	D. A. ACCT 364 - PRI-POLES, TOWERS & FIX	DEM364DAP	306,964,278	50,994,142	255,970,136
8	D. A. ACCT 364 - SEC-POLES, TOWERS & FIX	DEM364DAS	169,098,640	36,459,368	132,639,271
9	D. A. ACCT 365 - PRI - OVRHD COND & DEVICES	DEM365DAP	384,103,654	72,922,332	311,181,322
10	D. A. ACCT 365 - SEC - OVRHD COND & DEVICES	DEM365DAS	93,116,695	24,684,858	68,431,837
11	D. A. ACCT 366 - PRI - UNDERGROUND CONDUIT	DEM366DAP	32,783,336	7,799,663	24,983,673
12	D. A. ACCT 366 - SEC- UNDERGROUND CONDUIT	DEM366DAS	39,380,237	8,725,046	30,655,190
13	D. A. ACCT 367 - PRI - UNDGRD COND & DEVICE	DEM367DAP	108,262,829	27,174,239	81,088,590
14	D. A. ACCT 367 - SEC - UNDGRD COND & DEVICE	DEM367DAS	129,737,256	30,398,301	99,338,955
15	D. A. ACCT 368 - LINE TRANSORMERS	DEM368DA	419,358,146	59,647,952	359,710,194
16	ANNUAL BILLING DEMAND	DEM99	38,876,834	6,763,067	32,113,767
17	SPP DEMAND	SPPDEMAND	3,049	622	2,428
18	AVAILABLE-SUBSTATIONS	USERSUB	0	0	0
19	AVAILABLE-DIR ASSIGN SUBS	USERDASUB	0	0	0
20	AVAILABLE-PRI OVHD	USEROVHD	0	0	0
21	AVAILABLE-SECONDARY	USERSEC	0	0	0
22					
23					
24					
25	COMMODITY RELATED				
26	---				
27	FUEL ALLOCATION	FUEL	614,876,676	120,462,364	494,414,312
28	KWH SALES AT GENERATOR	ENERGY	23,462,250,824	4,130,615,297	19,331,635,527

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non- Arkansas) amounts on the the supporting schedules.

JURISDICTIONAL

		ALLOC	TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)
29	SALES OF ELECTRICITY - PRESENT FUEL	REVFUEL	614,876,676	120,462,364	494,414,312
30	KWH SALES AT METER	ENERGY99	22,225,948,325	3,867,122,238	18,358,826,087
31	MINE CLOSING	MINECLOSE	23,022,091,635	4,130,615,297	18,891,476,338
32	MINE CLOSING NFIRM RETAIL	MINECLOSEN	0	0	0
33	NON FIRM FUEL PRESENT FUEL	NFREVFUEL	0	0	0
34	FUEL ADJUSTMENT	FUELADJ	0	0	0
35	NON FIRM PROPOSED FUEL RETAIL	NFPROPFUEL	0	0	0
36	PROPOSED FUEL REVENUE	PROPFUEL	614,876,676	120,462,364	494,414,312
	CUSTOMER RELATED				
	--				
1	ANNUAL AVERAGE CUSTOMERS	CUST99	567,421	150,754	416,667
2	YEAR END NUMBER OF CUSTOMERS	CUST	567,530	150,754	416,776
3	WEIGHTED SERVICES	CUST369	564,263	124,610	439,653
4	WEIGHTED METERS	CUST370	755,451	153,057	602,394
5	ASSIGNED CUSTOMER INSTALLATIONS	CUST371L	93,533	16,468	77,065
6	LIGHTING ASSIGNMENTS	CUST373	86,113	14,239	71,874
7	WEIGHTED METERS	CUST902	564,917	126,340	438,577
8	CUSTOMER ACCOUNTING 903	CUST903	579,220	132,937	446,283
9	CUSTOMER INFO EXP ALLOC	CUSTINFO	567,524	150,754	416,770
10	CUSTOMER SERVICE EXP ALLOC	CUSTSRVC	567,524	150,754	416,770
11	ACTIVE CUSTOMER DEPOSITS	CUSTDEPA	0	0	0
12	CUSTOMERS IN AR & LA	CUSTARLA	381,821	150,754	231,067
13	RETAIL CUSTOMERS	CUSTRET	567,524	150,754	416,770
14	AVAILABLE-SERVICE DROP	CUSER1	0	0	0
15	AVAILABLE-SERVICE DROP	CUSER2	0	0	0
16	AVAILABLE-METERS	CUSER3	0	0	0
17	AVAILABLE-METERS	CUSER4	0	0	0
18	AVAILABLE-CUSTOMER SERVICES	CUSER5	564,917	126,340	438,577
19	AVAILABLE-CUSTOMER SERVICES	CUSER6	0	0	0
20	CUSTOMER ENERGY SPLIT 907-916	CUSER7	1.0099	0.21981	0.79009

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JURISDICTIONAL

		ALLOC	TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)
21	AVAILABLE-CUSTOMER BILLING	CUSER8	0	0	0
22	AVAILABLE-CUSTOMER BILLING	CUSER9	0	0	0
23	AVAILABLE-CUSTOMER LTG AND MISC REV	CUSER10	0	0	0
24	AVAILABLE-CUSTOMER LTG AND MISC REV	CUSER11	0	0	0
25	AVAILABLE-CUSTOMER OTHER	CUSER12	0	0	0
26					
27	REVENUE RELATED STRINGS				
28	--				
29	SALES OF ELECTRICITY-BASE	R40B	966,015,521	129,184,908	836,830,612
30	GROSS RECEIPTS FACTOR	RGR	0.000000	0.000000	0.000000
31	CLAIMED RATE OF RETURN	ROR	0.052125	0.052125	0.052125
32	CLAIMED FACTORING	RFACT	0.003205	0.003205	0.003205
33	PROPOSED REVENUES	PREV	1,043,474,124	203,711,789	839,762,334
34	FEDERAL INCOME TAX RATE		0.210000	0.210000	0.210000
35	LOUISIANA APPORTIONMENT FACTOR		0.243859	0.243859	0.243859
36	LOUISIANA INCOME TAX RATE		0.065000	0.065000	0.065000
37	ARKANSAS APPORTIONMENT FACTOR		0.243859	0.243859	0.243859
38	ARKANSAS INCOME TAX RATE		0.065000	0.065000	0.065000
	INTERNALLY DEVELOPED				
	--				
1	PRODUCTION PLANT	PRODPLT	3,133,644,267	609,249,318	2,524,394,949
2	PLANT ACCOUNT 352	PLT352	16,543,224	3,372,745	13,170,479
3	PLANT ACCOUNT 353	PLT353	687,889,404	140,243,262	547,646,142
4	PLANT ACCOUNTS 352 & 353	TRANSUB	704,432,628	143,616,007	560,816,621
5	PLANT ACCOUNTS 354, 355 & 356	TRANOHLN	1,201,298,279	244,914,354	956,383,925
6	PLANT ACCOUNT 357	TRANUGLN	2,325,898	474,192	1,851,706
7	TRANSMISSION PLANT	TRANPLT	2,017,942,947	411,407,560	1,606,535,386
8	PROD. & TRANS. PLANT	PTPLT	5,151,587,214	1,020,656,879	4,130,930,335
9	PLANT ACCOUNT 361	PLT361	8,435,022	2,518,993	5,916,029
10	PLANT ACCOUNT 362	PLT362	333,491,452	80,952,717	252,538,736

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non- Arkansas) amounts on the the supporting schedules.

JURISDICTIONAL

		ALLOC	TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)
11	PLANT ACCOUNT 368	PLT368	419,358,146	59,647,952	359,710,194
12	PLANT ACCOUNT 370	PLT370	91,533,265	18,544,958	72,988,307
13	PLANT ACCOUNT 371	PLT371	47,295,135	8,327,075	38,968,060
14	PLANT ACCOUNT 373	PLT373	45,422,361	7,510,701	37,911,660
15	PLANT ACCOUNT 361 & 362	DISTSUB	341,926,474	83,471,710	258,454,764
16	PLANT ACCOUNT 364 & 365	DISTOHLN	953,283,267	185,060,700	768,222,567
17	PLANT ACCOUNT 366 & 367	DISTUGLN	310,163,657	74,097,249	236,066,409
18	DISTRIBUTION PLANT	DISTPLT	2,315,330,983	460,470,865	1,854,860,118
19	TRANS. & DISTR. PLANT	TDPLT	4,333,273,930	871,878,425	3,461,395,505
20	PROD. , TRANS., & DISTR. PLANT	PTDPLT	7,466,918,197	1,481,127,744	5,985,790,453
21	GENERAL PLANT EXCL ADJUSTMENTS	GENPLTX	302,894,350	61,126,719	241,767,630
22	GENERAL PLANT	GENPLT	302,894,350	61,126,719	241,767,630
23	TOTAL ELECTRIC PLANT IN SERVICE	PLANT	7,927,359,543	1,573,040,891	6,354,318,652
24	NET PLANT IN SERVICE	NETPLT	5,052,439,002	1,005,390,167	4,047,048,836
25	RATE BASE	RBX	5,942,303,243	1,181,137,178	4,761,166,065
26	OPERATING EXPENSE ACCT NO. 500	OX500	18,059,735	3,445,742	14,613,993
27	OPERATING EXPENSE ACCT NO. 501	OX501	19,388,616	3,413,437	15,975,179
28	OPERATING EXPENSE ACCT NO. 502	OX502	15,586,826	3,030,422	12,556,404
29	OPERATING EXPENSE ACCT NO. 505	OX505	6,094,085	1,184,824	4,909,261
30	OPERATING EXPENSE ACCT NO. 506	OX506	20,741,309	4,032,566	16,708,743
31	MAINTENANCE EXPENSE ACCT NO. 510	MX510	5,273,141	937,255	4,335,886
32	MAINTENANCE EXPENSE ACCT NO. 511	MX511	2,837,655	551,702	2,285,953
33	MAINTENANCE EXPENSE ACCT NO. 512	MX512	45,774,504	8,058,769	37,715,735
34	MAINTENANCE EXPENSE ACCT NO. 513	MX513	5,579,530	982,297	4,597,233
35	MAINTENANCE EXPENSE ACCT NO. 514	MX514	4,106,074	798,311	3,307,763
36	OPERATING EXPENSE ACCT NO. 546	OX546	0	0	0
37	OPERATING EXPENSE ACCT NO. 548	OX548	635,668	123,588	512,080
38	OPERATING EXPENSE ACCT NO. 549	OX549	0	0	0
39	MAINTENANCE EXPENSE ACCT NO. 551	MX551	0	0	0
40	MAINTENANCE EXPENSE ACCT NO. 552	MX552	0	0	0

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non- Arkansas) amounts on the the supporting schedules.

JURISDICTIONAL

		ALLOC	TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)
	INTERNALLY DEVELOPED (CON'T)				
	--				
1	MAINTENANCE EXPENSE ACCT NO. 553	MX553	633,906	123,245	510,661
2	MAINTENANCE EXPENSE ACCT NO. 554	MX554	16,954	3,296	13,658
3	OPERATING EXPENSE ACCT NO. 556	OX556	1,922,357	373,748	1,548,609
4	OPERATING EXPENSE ACCT NO. 557	OX557	3,693,825	718,161	2,975,664
5	OPERATING EXPENSE ACCT NO. 560	OX560	7,445,340	1,517,917	5,927,423
6	OPERATING EXPENSE ACCT NO. 561	OX561	14,366,768	2,929,021	11,437,747
7	OPERATING EXPENSE ACCT NO. 562	OX562	538,307	109,747	428,560
8	OPERATING EXPENSE ACCT NO. 563	OX563	424,831	86,612	338,219
9	OPERATING EXPENSE ACCT NO. 564	OX564	0	0	0
10	OPERATING EXPENSE ACCT NO. 565	OX565	105,886,115	21,587,502	84,298,613
11	OPERATING EXPENSE ACCT NO. 566	OX566	1,960,018	399,598	1,560,420
12	MAINTENANCE EXPENSE ACCT NO. 568	MX568	41,207	8,401	32,806
13	MAINTENANCE EXPENSE ACCT NO. 569	MX569	574,157	117,056	457,101
14	MAINTENANCE EXPENSE ACCT NO. 570	MX570	3,525,596	718,780	2,806,816
15	MAINTENANCE EXPENSE ACCT NO. 571	MX571	10,344,498	2,108,982	8,235,516
16	MAINTENANCE EXPENSE ACCT NO. 572	MX572	952	194	758
17	MAINTENANCE EXPENSE ACCT NO. 573	MX573	38,473	7,844	30,629
18	OPERATING EXPENSE ACCT NO. 580	OX580	2,383,634	482,490	1,901,144
19	OPERATING EXPENSE ACCT NO. 581	OX581	31,527	6,270	25,257
20	OPERATING EXPENSE ACCT NO. 582	OX582	426,419	103,510	322,909
21	OPERATING EXPENSE ACCT NO. 583	OX583	3,104,881	602,750	2,502,131
22	OPERATING EXPENSE ACCT NO. 584	OX584	2,128,460	508,483	1,619,977
23	OPERATING EXPENSE ACCT NO. 585	OX585	201,658	33,345	168,313
24	OPERATING EXPENSE ACCT NO. 586	OX586	3,447,028	698,380	2,748,648
25	OPERATING EXPENSE ACCT NO. 587	OX587	717,753	126,372	591,381
26	OPERATING EXPENSE ACCT NO. 588	OX588	19,180,121	3,814,525	15,365,596
27	OPERATING EXPENSE ACCT NO. 589	OX589	891,782	177,357	714,425
28	MAINTENANCE EXPENSE ACCT NO. 590	MX590	368,237	72,853	295,384
29	MAINTENANCE EXPENSE ACCT NO. 591	MX591	22,464	6,709	15,755
30	MAINTENANCE EXPENSE ACCT NO. 592	MX592	680,258	165,128	515,130

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non- Arkansas) amounts on the the supporting schedules.

JURISDICTIONAL

		ALLOC	TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)
31	MAINTENANCE EXPENSE ACCT NO. 593	MX593	24,759,034	4,806,467	19,952,567
32	MAINTENANCE EXPENSE ACCT NO. 594	MX594	1,014,404	242,338	772,066
33	MAINTENANCE EXPENSE ACCT NO. 595	MX595	138,531	19,704	118,827
34	MAINTENANCE EXPENSE ACCT NO. 596	MX596	389,545	64,412	325,133
35	MAINTENANCE EXPENSE ACCT NO. 597	MX597	474,232	96,081	378,151
36	MAINTENANCE EXPENSE ACCT NO. 598	MX598	244,347	43,021	201,326
37	OPERATING EXPENSE ACCT NO. 901	OX901	680,545	162,910	517,635
38	OPERATING EXPENSE ACCT NO. 902	OX902	2,149,818	480,793	1,669,025
39	OPERATING EXPENSE ACCT NO. 903	OX903	16,781,707	4,065,728	12,715,979
40	OPERATING EXPENSE ACCT NO. 904	OX904	2,608,677	348,857	2,259,820

INTERNALLY DEVELOPED (CON'T)

1	OPERATING EXPENSE ACCT NO. 905	OX905	105,705	25,304	80,401
2	OPERATING EXPENSE ACCT NO. 907	OX907	694,860	218,846	476,014
3	OPERATING EXPENSE ACCT NO. 908	OX908	2,407,814	758,779	1,649,035
4	OPERATING EXPENSE ACCT NO. 909	OX909	14,453	3,146	11,307
5	OPERATING EXPENSE ACCT NO. 910	OX910	8,545	1,860	6,685
6	OPERATING EXPENSE ACCT NO. 911	OX911	321	70	251
7	OPERATING EXPENSE ACCT NO. 912	OX912	166,320	36,201	130,119
8	OPERATING EXPENSE ACCT NO. 913	OX913	(22,410)	(4,878)	(17,532)
9	OPERATING EXPENSE ACCT NO. 916	OX916	0	0	0
10	OPERATING EXPENSE ACCT NO. 920	OX920	34,324,100	6,926,902	27,397,198
11	OPERATING EXPENSE ACCT NO. 921	OX921	2,499,100	504,340	1,994,760
12	OPERATING EXPENSE ACCT NO. 922	OX922	(3,684,920)	(743,649)	(2,941,271)
13	OPERATING EXPENSE ACCT NO. 923	OX923	17,643,733	3,560,659	14,083,074
14	1/8 O&M LESS FUEL & PURCHASED PWR	OMX	58,702,072	11,387,376	47,314,696
15	DEPRECIATION EXPENSE	DEPREXP	213,866,853	42,372,026	171,494,827
16	AD VALOREM TAXES	PROPTAX	62,321,326	12,366,538	49,954,788
17	LABOR ACCOUNTS 501 THRU 507	LAB501_507	18,886,524	3,603,491	15,283,032
18	LABOR ACCOUNTS 511 THRU 514	LAB511_514	15,267,593	2,713,683	12,553,910

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JURISDICTIONAL

		ALLOC	TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)
19	LABOR ACCOUNTS 547 THRU 550	LAB547_550	329,502	64,062	265,439
20	LABOR ACCOUNTS 552 THRU 554	LAB552_554	183,762	35,727	148,034
21	LABOR ACCOUNTS 561 THRU 567	LAB561_567	1,836,632	374,443	1,462,189
22	LABOR ACCOUNTS 569 THRU 573	LAB569_573	2,919,407	595,193	2,324,214
23	LABOR ACCOUNTS 581 THRU 589	LAB581_589	15,919,983	3,222,491	12,697,492
24	LABOR ACCOUNTS 591 THRU 598	LAB591_598	8,073,339	1,597,251	6,476,088
25	LABOR ACCOUNTS 902 THRU 905	LAB902_905	9,537,278	2,283,046	7,254,232
26	LABOR ACCOUNTS 908 THRU 910	LAB908_910	2,374,401	747,817	1,626,585
27	LABOR ACCOUNTS 912 THRU 916	LAB912_916	773	168	605
28	PAYROLL EXCLUDING A&G	LABORX	99,151,589	20,001,234	79,150,355
29	RETAIL PAYROLL EXCLUDING A&G	LABORXR	91,233,989	20,001,234	71,232,754
30	TOTAL PAYROLL	LABORT	117,992,576	23,811,930	94,180,646
31	ACCT 903 EXCL BILLING	OX903X	0	0	0
32	ACCT 903 BILLING	OX903B	16,781,707	4,065,728	12,715,979
33	PRODUCTION LABOR	LABPROD	51,229,086	9,553,314	41,675,773
34	TRANSMISSION LABOR	LABTRAN	8,734,052	1,780,652	6,953,400
35	DISTR LABOR EXCL METERING	LABDIST	22,422,973	4,499,967	17,923,006
36	CUST SERVICE LABOR EXCL METER & BILLING	LABCUSSV	12,162,364	3,203,616	8,958,748
37	METERING LABOR	LABMETER	4,603,113	963,684	3,639,429
38	BILLING LABOR	LABBILL	0	0	0

INTERNALLY DEVELOPED (CON'T)

1	SALES REVENUE	REVSALES	966,015,521	129,184,908	836,830,612
2	0.5*PRODPLT + 0.95*TDPLT	PTDPLTW	5,683,432,367	1,132,909,163	4,550,523,204
3	REV DEF @ CLAIMED * FACTORING	FACTC	0.00000	0.00000	0.00000
4	REV DEF @ PROPOSED * FACTORING	FACTP	0.00000	0.00000	0.00000
5	COS @ CLAIMED * AR REV REL TAX	REVFACC1	1.00000	1.00000	0.00000
6	COS @ CLAIMED * LA REV RELA TAX	REVFACC2	1.00000	0.00000	1.00000

SOUTHWESTERN ELECTRIC POWER COMPANY
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Schedule: G-4
Development of Allocation Group
Jurisdiction

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non- Arkansas) amounts on the the supporting schedules.

JURISDICTIONAL

	ALLOC	TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)
7 COS @ CLAIMED * TX REV REL TAX	REVFACC3	1.00000	0.00000	1.00000
8 PROPOSED REV * AR REV REL TX	REVFACP1	1.00000	1.00000	0.00000
9 PROPOSED REV * LA REV REL TAX	REVFACP2	1.00000	0.00000	1.00000
10 PROPOSED REV * TX REV REL TAX	REVFACP3	1.00000	0.00000	1.00000
11 FUEL - RETAIL	FUELR	15,753,615	3,413,437	12,340,178
12 FUEL - WHOLESALE	FUELW	3,635,001	0	3,635,001
13 SALES REVENUE - RETAIL	REVSALESR	881,478,997	129,184,908	752,294,088
14 SALES REVENUE - WHOLESALE	REVSALESW	84,536,524	0	84,536,524
15 SALES REVENUE - ARKANSAS	REVSALEAR	129,184,908	129,184,908	0
16 SALES REVENUE - LOUISIANA	REVSALELA	386,074,219	0	386,074,219
17 SALES REVENUE - TEXAS	REVSALETX	366,219,869	0	366,219,869
18 PRODUCTION PLANT - TEXAS	PRODPLTTX	1,125,878,857	0	1,125,878,857
19 DISTRIBUTION PLANT - LOUISIANA	DISTPLTLA	1,030,238,316	0	1,030,238,316
20 RETAIL REVENUE LA	RREVLA	386,074,219	0	386,074,219
21 TAXABLE INCOME LA	TAXINCLA	51,263,297	0	51,263,297
22 TAXABLE INCOME AR	TAXINCAR	(31,845,328)	(31,845,328)	0
23 PLANT LA	PLANTLA	3,014,422,960	0	3,014,422,960
24 PLANT AR	PLANTAR	1,573,040,891	1,573,040,891	0
25 DEMAND PROD WHOLESALE	DPRODWH	319,702,092	0	319,702,092
26 DEMAND PROD ARKANSAS	DPRODAR	600,667,049	600,667,049	0
27 DEMAND PROD LOUISIANA	DPRODLA	1,059,113,622	0	1,059,113,622
28 DEMAND PROD TEXAS	DPRODTX	1,110,019,019	0	1,110,019,019
29 DEMAND TRAN WHOLESALE	DTRANWH	73,595,619	0	73,595,619
30 DEMAND TRAN ARKANSAS	DTRANAR	411,230,169	411,230,169	0
31 DEMAND TRAN LOUISIANA	DTRANLA	737,815,170	0	737,815,170
32 DEMAND TRAN TEXAS	DTRANTX	794,431,892	0	794,431,892
33 DEMAND DIST WHOLESALE	DDISTWH	1,238,963	0	1,238,963
34 DEMAND DIST ARKANSAS	DDISTAR	461,207,803	461,207,803	0
35 DEMAND DIST LOUISIANA	DDISTLA	1,031,887,109	0	1,031,887,109
36 DEMAND DIST TEXAS	DDISTTX	824,702,564	0	824,702,564
37 DEMAND GENERAL WHOLESALE	DGENLWH	24,203,774	0	24,203,774
38 DEMAND GENERAL ARKANSAS	DGENLAR	61,126,719	61,126,719	0

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Schedule: G-4
Development of Allocation Group
Jurisdiction

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JURISDICTIONAL

		ALLOC	TOTAL COMPANY	AT ISSUE ARKANSAS RETAIL	ALL OTHER
			(1)	(2)	(3)
39	DEMAND GENERAL LOUISIANA	DGENLLA	111,516,509	0	111,516,509
40	DEMAND GENERAL TEXAS	DGENLTX	106,047,347	0	106,047,347
	INTERNALLY DEVELOPED (CON'T)				
	--				
1	PRODUCTION PLANT - TEXAS RETAIL	PRODPLTT	1,125,878,857	0	1,125,878,857
2	LABOR 902 & 903	LAB902_903	9,520,160	2,278,948	7,241,212
3	SALES REVENUE - AR RETAIL	RVSALEARR	129,184,908	129,184,908	0
4	SALES REVENUE - LA RETAIL	RVSALELAR	386,074,219	0	386,074,219
5	SALES REVENUE - TX RETAIL	RVSALETXR	366,219,869	0	366,219,869
6	DIST PLANT BEFORE CONTRA ADJ	DISTPLTX	2,319,036,440	461,207,803	1,857,828,637
7	STATE INCOME TAX	SIT	3,133,910	(1,040,062)	4,173,972
8	RETAIL PRODUCTION PLANT	PRODPLTR	2,809,374,305	609,249,318	2,200,124,986
9	TOTAL kWh AT GEN - ARKANSAS	KWHAR	4,130,615,297	4,130,615,297	0
10	TOTAL kWh AT GEN- LOUISIANA	KWHLA	7,169,966,645	0	7,169,966,645
11	TOTAL kWh AT GEN- TEXAS	KWHTX	7,322,778,169	0	7,322,778,169
12	INTANGIBLE PLANT	INTPLT	157,546,996	30,786,428	126,760,568
13	DEMPROD RETAIL	DEMRTAIL	3,592	779	2,813
14	FIT TEMPORARY DIFFERENCES	FITTEMP	(56,178,938)	(11,028,177)	(45,150,761)
15	Total Depr Expense	DEPEXP	213,866,853	42,372,026	171,494,827
16	State Tax Calculated	STATETAXCALC	2,340,395	(776,715)	3,117,110
17	Composite Tax Rate (FIT and AR State)	COMPTR	26.1350%	26.1350%	26.1350%
18	Combined Tax Gross Up (FIT and AR State)	TAX GU	35.3821%	35.3821%	35.3821%
19	FACTORING RATE	RFACT	0.3205%	0.3205%	0.3205%
20	Gross Revenue Conversion Factor	REVCONV	1.358174	1.358174	1.358174
21	AVAILABLE	AVAIL	0	0	0
	SCHEDULE G-4				
	RATIO TABLE				
	CAPACITY RELATED				
	--				
1	PRODUCTION ALLOCATOR	DEMPROD	1.000000	0.194422	0.805578

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non- Arkansas) amounts on the the supporting schedules.

JURISDICTIONAL

		ALLOC	TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)
2					
3	TRANSMISSION FUNCTION	DEMTRANS	1.000000	0.203875	0.796125
4	D. A. ACCT 360 - LAND	DEM360DA	1.000000	0.242120	0.757880
5	D. A. ACCT 361 - STRUCTURES & IMPROVE	DEM361DA	1.000000	0.298635	0.701365
6	D. A. ACCT 362 - STATION EQUIPMENT	DEM362DA	1.000000	0.242743	0.757257
7	D. A. ACCT 364 - PRI-POLES, TOWERS & FIX	DEM364DAP	1.000000	0.166124	0.833876
8	D. A. ACCT 364 - SEC-POLES, TOWERS & FIX	DEM364DAS	1.000000	0.215610	0.784390
9	D. A. ACCT 365 - PRI - OVRHD COND & DEVICES	DEM365DAP	1.000000	0.189851	0.810149
10	D. A. ACCT 365 - SEC - OVRHD COND & DEVICES	DEM365DAS	1.000000	0.265096	0.734904
11	D. A. ACCT 366 - PRI - UNDERGROUND CONDUIT	DEM366DAP	1.000000	0.237915	0.762085
12	D. A. ACCT 366 - SEC- UNDERGROUND CONDUIT	DEM366DAS	1.000000	0.221559	0.778441
13	D. A. ACCT 367 - PRI - UNDGRD COND & DEVICE	DEM367DAP	1.000000	0.251002	0.748998
14	D. A. ACCT 367 - SEC - UNDGRD COND & DEVICE	DEM367DAS	1.000000	0.234307	0.765693
15	D. A. ACCT 368 - LINE TRANSORMERS	DEM368DA	1.000000	0.142236	0.857764
16	ANNUAL BILLING DEMAND	DEM99	1.000000	0.173961	0.826039
17	SPP DEMAND	SPPDEMAND	1.000000	0.203875	0.796125
18	AVAILABLE-SUBSTATIONS	USERSUB	0.000000	0.000000	0.000000
19	AVAILABLE-DIR ASSIGN SUBS	USERDASUB	0.000000	0.000000	0.000000
20	AVAILABLE-PRI OVHD	USEROVHD	0.000000	0.000000	0.000000
21	AVAILABLE-SECONDARY	USERSEC	0.000000	0.000000	0.000000
22					
23					
24					
25	COMMODITY RELATED				
26	--				
27	FUEL ALLOCATION	FUEL	1.000000	0.195913	0.804087
28	KWH SALES AT GENERATOR	ENERGY	1.000000	0.176054	0.823946
29	SALES OF ELECTRICITY - PRESENT FUEL	REVFUEL	1.000000	0.195913	0.804087
30	KWH SALES AT METER	ENERGY99	1.019804	0.173991	0.845813
31	MINE CLOSING	MINECLOSE	1.000000	0.179420	0.820580
32	MINE CLOSING NFIRM RETAIL	MINECLOSEN	0.000000	0.000000	0.000000
33	NON FIRM FUEL PRESENT FUEL	NFREVFUEL	0.000000	0.000000	0.000000

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Schedule: G-4
Development of Allocation Group
Jurisdiction

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non- Arkansas) amounts on the the supporting schedules.

JURISDICTIONAL

		ALLOC	TOTAL COMPANY	AT ISSUE ARKANSAS RETAIL	ALL OTHER
			(1)	(2)	(3)
34	FUEL ADJUSTMENT	FUELADJ	0.000000	0.000000	0.000000
35	NON FIRM PROPOSED FUEL RETAIL	NFPROPFUEL	0.000000	0.000000	0.000000
36	PROPOSED FUEL REVENUE	PROPFUEL	1.000000	0.195913	0.804087
	CUSTOMER RELATED				
	--				
1	ANNUAL AVERAGE CUSTOMERS	CUST99	1.000000	0.265683	0.734317
2	YEAR END NUMBER OF CUSTOMERS	CUST	1.000000	0.265632	0.734368
3	WEIGHTED SERVICES	CUST369	1.000000	0.220837	0.779163
4	WEIGHTED METERS	CUST370	1.000000	0.202603	0.797397
5	ASSIGNED CUSTOMER INSTALLATIONS	CUST371L	1.000000	0.176066	0.823934
6	LIGHTING ASSIGNMENTS	CUST373	1.000000	0.165353	0.834647
7	WEIGHTED METERS	CUST902	1.000000	0.223643	0.776357
8	CUSTOMER ACCOUNTING 903	CUST903	1.000000	0.229511	0.770489
9	CUSTOMER INFO EXP ALLOC	CUSTINFO	1.000000	0.265635	0.734365
10	CUSTOMER SERVICE EXP ALLOC	CUSTSRVC	1.000000	0.265635	0.734365
11	ACTIVE CUSTOMER DEPOSITS	CUSTDEPA	0.000000	0.000000	0.000000
12	CUSTOMERS IN AR & LA	CUSTARLA	1.000000	0.394829	0.605171
13	RETAIL CUSTOMERS	CUSTRET	1.000000	0.265635	0.734365
14	AVAILABLE-SERVICE DROP	CUSER1	0.000000	0.000000	0.000000
15	AVAILABLE-SERVICE DROP	CUSER2	0.000000	0.000000	0.000000
16	AVAILABLE-METERS	CUSER3	0.000000	0.000000	0.000000
17	AVAILABLE-METERS	CUSER4	0.000000	0.000000	0.000000
18	AVAILABLE-CUSTOMER SERVICES	CUSER5	1.000000	0.223643	0.776357
19	AVAILABLE-CUSTOMER SERVICES	CUSER6	0.000000	0.000000	0.000000
20	CUSTOMER ENERGY SPLIT 907-916	CUSER7	1.000000	0.217656	0.782344
21	AVAILABLE-CUSTOMER BILLING	CUSER8	0.000000	0.000000	0.000000
22	AVAILABLE-CUSTOMER BILLING	CUSER9	0.000000	0.000000	0.000000
23	AVAILABLE-CUSTOMER LTG AND MISC REV	CUSER10	0.000000	0.000000	0.000000
24	AVAILABLE-CUSTOMER LTG AND MISC REV				
25	AVAILABLE-CUSTOMER OTHER				

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JURISDICTIONAL

		ALLOC	TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)
26					
27	REVENUE RELATED STRINGS				
28	--				
29	SALES OF ELECTRICITY-BASE	R40B	1.000000	0.133730	0.866270
30	GROSS RECEIPTS FACTOR	RGR	4.000000	1.000000	3.000000
31	CLAIMED RATE OF RETURN	ROR	4.000000	1.000000	3.000000
32	CLAIMED FACTORING	RFACT	4.000000	1.000000	3.000000
33	PROPOSED REVENUES	PREV	0.000000	0.000000	0.000000
34	FEDERAL INCOME TAX RATE		4.000000	1.000000	3.000000
35	LOUISIANA APPORTIONMENT FACTOR		4.000000	1.000000	3.000000
36	LOUISIANA INCOME TAX RATE		4.000000	1.000000	3.000000
37	ARKANSAS APPORTIONMENT FACTOR		4.000000	1.000000	3.000000
38	ARKANSAS INCOME TAX RATE		4.000000	1.000000	3.000000
	INTERNALLY DEVELOPED				
	--				
1	PRODUCTION PLANT	PRODPLT	1.000000	0.194422	0.805578
2	PLANT ACCOUNT 352	PLT352	1.000000	0.203875	0.796125
3	PLANT ACCOUNT 353	PLT353	1.000000	0.203875	0.796125
4	PLANT ACCOUNTS 352 & 353	TRANSUB	1.000000	0.203875	0.796125
5	PLANT ACCOUNTS 354, 355 & 356	TRANOHLN	1.000000	0.203875	0.796125
6	PLANT ACCOUNT 357	TRANUGLN	1.000000	0.203875	0.796125
7	TRANSMISSION PLANT	TRANPLT	1.000000	0.203875	0.796125
8	PROD. & TRANS. PLANT	PTPLT	1.000000	0.198125	0.801875
9	PLANT ACCOUNT 361	PLT361	1.000000	0.298635	0.701365
10	PLANT ACCOUNT 362	PLT362	1.000000	0.242743	0.757257
11	PLANT ACCOUNT 368	PLT368	1.000000	0.142236	0.857764
12	PLANT ACCOUNT 370	PLT370	1.000000	0.202603	0.797397
13	PLANT ACCOUNT 371	PLT371	1.000000	0.176066	0.823934
14	PLANT ACCOUNT 373	PLT373	1.000000	0.165353	0.834647
15	PLANT ACCOUNT 361 & 362	DISTSUB	1.000000	0.244122	0.755878

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JURISDICTIONAL

		ALLOC	TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)
16	PLANT ACCOUNT 364 & 365	DISTOHLN	1.000000	0.194130	0.805870
17	PLANT ACCOUNT 366 & 367	DISTUGLN	1.000000	0.238897	0.761103
18	DISTRIBUTION PLANT	DISTPLT	1.000000	0.198879	0.801121
19	TRANS. & DISTR. PLANT	TDPLT	1.000000	0.201205	0.798795
20	PROD. , TRANS., & DISTR. PLANT	PTDPLT	1.000000	0.198359	0.801641
21	GENERAL PLANT EXCL ADJUSTMENTS	GENPLTX	1.000000	0.201809	0.798191
22	GENERAL PLANT	GENPLT	1.000000	0.201809	0.798191
23	TOTAL ELECTRIC PLANT IN SERVICE	PLANT	1.000000	0.198432	0.801568
24	NET PLANT IN SERVICE	NETPLT	1.000000	0.198991	0.801009
25	RATE BASE	RBX	1.000000	0.198768	0.801232
26	OPERATING EXPENSE ACCT NO. 500	OX500	1.000000	0.190797	0.809203
27	OPERATING EXPENSE ACCT NO. 501	OX501	1.000000	0.176054	0.823946
28	OPERATING EXPENSE ACCT NO. 502	OX502	1.000000	0.194422	0.805578
29	OPERATING EXPENSE ACCT NO. 505	OX505	1.000000	0.194422	0.805578
30	OPERATING EXPENSE ACCT NO. 506	OX506	1.000000	0.194422	0.805578
31	MAINTENANCE EXPENSE ACCT NO. 510	MX510	1.000000	0.177741	0.822259
32	MAINTENANCE EXPENSE ACCT NO. 511	MX511	1.000000	0.194422	0.805578
33	MAINTENANCE EXPENSE ACCT NO. 512	MX512	1.000000	0.176054	0.823946
34	MAINTENANCE EXPENSE ACCT NO. 513	MX513	1.000000	0.176054	0.823946
35	MAINTENANCE EXPENSE ACCT NO. 514	MX514	1.000000	0.194422	0.805578
36	OPERATING EXPENSE ACCT NO. 546	OX546	0.000000	0.000000	0.000000
37	OPERATING EXPENSE ACCT NO. 548	OX548	1.000000	0.194422	0.805578
38	OPERATING EXPENSE ACCT NO. 549	OX549	0.000000	0.000000	0.000000
39	MAINTENANCE EXPENSE ACCT NO. 551	MX551	0.000000	0.000000	0.000000
40	MAINTENANCE EXPENSE ACCT NO. 552	MX552	0.000000	0.000000	0.000000
	INTERNALLY DEVELOPED (CON'T)				

1	MAINTENANCE EXPENSE ACCT NO. 553	MX553	1.000000	0.194422	0.805578
2	MAINTENANCE EXPENSE ACCT NO. 554	MX554	1.000000	0.194422	0.805578
3	OPERATING EXPENSE ACCT NO. 556	OX556	1.000000	0.194422	0.805578

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non- Arkansas) amounts on the the supporting schedules.

JURISDICTIONAL

		ALLOC	TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)
4	OPERATING EXPENSE ACCT NO. 557	OX557	1.000000	0.194422	0.805578
5	OPERATING EXPENSE ACCT NO. 560	OX560	1.000000	0.203875	0.796125
6	OPERATING EXPENSE ACCT NO. 561	OX561	1.000000	0.203875	0.796125
7	OPERATING EXPENSE ACCT NO. 562	OX562	1.000000	0.203875	0.796125
8	OPERATING EXPENSE ACCT NO. 563	OX563	1.000000	0.203875	0.796125
9	OPERATING EXPENSE ACCT NO. 564	OX564	0.000000	0.000000	0.000000
10	OPERATING EXPENSE ACCT NO. 565	OX565	1.000000	0.203875	0.796125
11	OPERATING EXPENSE ACCT NO. 566	OX566	1.000000	0.203875	0.796125
12	MAINTENANCE EXPENSE ACCT NO. 568	MX568	1.000000	0.203875	0.796125
13	MAINTENANCE EXPENSE ACCT NO. 569	MX569	1.000000	0.203875	0.796125
14	MAINTENANCE EXPENSE ACCT NO. 570	MX570	1.000000	0.203875	0.796125
15	MAINTENANCE EXPENSE ACCT NO. 571	MX571	1.000000	0.203875	0.796125
16	MAINTENANCE EXPENSE ACCT NO. 572	MX572	1.000000	0.203875	0.796125
17	MAINTENANCE EXPENSE ACCT NO. 573	MX573	1.000000	0.203875	0.796125
18	OPERATING EXPENSE ACCT NO. 580	OX580	1.000000	0.202418	0.797582
19	OPERATING EXPENSE ACCT NO. 581	OX581	1.000000	0.198879	0.801121
20	OPERATING EXPENSE ACCT NO. 582	OX582	1.000000	0.242743	0.757257
21	OPERATING EXPENSE ACCT NO. 583	OX583	1.000000	0.194130	0.805870
22	OPERATING EXPENSE ACCT NO. 584	OX584	1.000000	0.238897	0.761103
23	OPERATING EXPENSE ACCT NO. 585	OX585	1.000000	0.165353	0.834647
24	OPERATING EXPENSE ACCT NO. 586	OX586	1.000000	0.202603	0.797397
25	OPERATING EXPENSE ACCT NO. 587	OX587	1.000000	0.176066	0.823934
26	OPERATING EXPENSE ACCT NO. 588	OX588	1.000000	0.198879	0.801121
27	OPERATING EXPENSE ACCT NO. 589	OX589	1.000000	0.198879	0.801121
28	MAINTENANCE EXPENSE ACCT NO. 590	MX590	1.000000	0.197843	0.802157
29	MAINTENANCE EXPENSE ACCT NO. 591	MX591	1.000000	0.298635	0.701365
30	MAINTENANCE EXPENSE ACCT NO. 592	MX592	1.000000	0.242743	0.757257
31	MAINTENANCE EXPENSE ACCT NO. 593	MX593	1.000000	0.194130	0.805870
32	MAINTENANCE EXPENSE ACCT NO. 594	MX594	1.000000	0.238897	0.761103
33	MAINTENANCE EXPENSE ACCT NO. 595	MX595	1.000000	0.142236	0.857764
34	MAINTENANCE EXPENSE ACCT NO. 596	MX596	1.000000	0.165353	0.834647
35	MAINTENANCE EXPENSE ACCT NO. 597	MX597	1.000000	0.202603	0.797397

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non- Arkansas) amounts on the the supporting schedules.

JURISDICTIONAL

		ALLOC	TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)
36	MAINTENANCE EXPENSE ACCT NO. 598	MX598	1.000000	0.176066	0.823934
37	OPERATING EXPENSE ACCT NO. 901	OX901	1.000000	0.239381	0.760619
38	OPERATING EXPENSE ACCT NO. 902	OX902	1.000000	0.223643	0.776357
39	OPERATING EXPENSE ACCT NO. 903	OX903	1.000000	0.242271	0.757729
40	OPERATING EXPENSE ACCT NO. 904	OX904	1.000000	0.133730	0.866270
	INTERNALLY DEVELOPED (CON'T)				
	--				
1	OPERATING EXPENSE ACCT NO. 905	OX905	1.000000	0.239381	0.760619
2	OPERATING EXPENSE ACCT NO. 907	OX907	1.000000	0.314950	0.685050
3	OPERATING EXPENSE ACCT NO. 908	OX908	1.000000	0.315132	0.684868
4	OPERATING EXPENSE ACCT NO. 909	OX909	1.000000	0.217656	0.782344
5	OPERATING EXPENSE ACCT NO. 910	OX910	1.000000	0.217656	0.782344
6	OPERATING EXPENSE ACCT NO. 911	OX911	1.000000	0.217656	0.782344
7	OPERATING EXPENSE ACCT NO. 912	OX912	1.000000	0.217656	0.782344
8	OPERATING EXPENSE ACCT NO. 913	OX913	1.000000	0.217656	0.782344
9	OPERATING EXPENSE ACCT NO. 916	OX916	0.000000	0.000000	0.000000
10	OPERATING EXPENSE ACCT NO. 920	OX920	1.000000	0.201809	0.798191
11	OPERATING EXPENSE ACCT NO. 921	OX921	1.000000	0.201809	0.798191
12	OPERATING EXPENSE ACCT NO. 922	OX922	1.000000	0.201809	0.798191
13	OPERATING EXPENSE ACCT NO. 923	OX923	1.000000	0.201809	0.798191
14	1/8 O&M LESS FUEL & PURCHASED PWR	OMX	1.000000	0.193986	0.806014
15	DEPRECIATION EXPENSE	DEPREXP	1.000000	0.198123	0.801877
16	AD VALOREM TAXES	PROPTAX	1.000000	0.198432	0.801568
17	LABOR ACCOUNTS 501 THRU 507	LAB501_507	1.000000	0.190797	0.809203
18	LABOR ACCOUNTS 511 THRU 514	LAB511_514	1.000000	0.177741	0.822259
19	LABOR ACCOUNTS 547 THRU 550	LAB547_550	1.000000	0.194422	0.805578
20	LABOR ACCOUNTS 552 THRU 554	LAB552_554	1.000000	0.194422	0.805578
21	LABOR ACCOUNTS 561 THRU 567	LAB561_567	1.000000	0.203875	0.796125
22	LABOR ACCOUNTS 569 THRU 573	LAB569_573	1.000000	0.203875	0.796125
23	LABOR ACCOUNTS 581 THRU 589	LAB581_589	1.000000	0.202418	0.797582

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non- Arkansas) amounts on the the supporting schedules.

JURISDICTIONAL

		ALLOC	TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)
24	LABOR ACCOUNTS 591 THRU 598	LAB591_598	1.000000	0.197843	0.802157
25	LABOR ACCOUNTS 902 THRU 905	LAB902_905	1.000000	0.239381	0.760619
26	LABOR ACCOUNTS 908 THRU 910	LAB908_910	1.000000	0.314950	0.685050
27	LABOR ACCOUNTS 912 THRU 916	LAB912_916	1.000000	0.217656	0.782344
28	PAYROLL EXCLUDING A&G	LABORX	1.000000	0.201724	0.798276
29	RETAIL PAYROLL EXCLUDING A&G	LABORXR	1.000000	0.219230	0.780770
30	TOTAL PAYROLL	LABORT	1.000000	0.201809	0.798191
31	ACCT 903 EXCL BILLING	OX903X	0.000000	0.000000	0.000000
32	ACCT 903 BILLING	OX903B	1.000000	0.242271	0.757729
33	PRODUCTION LABOR	LABPROD	1.000000	0.186482	0.813518
34	TRANSMISSION LABOR	LABTRAN	1.000000	0.203875	0.796125
35	DISTR LABOR EXCL METERING	LABDIST	1.000000	0.200686	0.799314
36	CUST SERVICE LABOR EXCL METER & BILLING	LABCUSSV	1.000000	0.263404	0.736596
37	METERING LABOR	LABMETER	1.000000	0.209355	0.790645
38	BILLING LABOR	LABBILL	0.000000	0.000000	0.000000

INTERNALLY DEVELOPED (CON'T)

1	SALES REVENUE	REVSALES	1.000000	0.133730	0.866270
2	0.5*PRODPLT + 0.95*TDPLT	PTDPLTW	1.000000	0.199335	0.800665
3	REV DEF @ CLAIMED * FACTORING	FACTC	0.000000	0.000000	0.000000
4	REV DEF @ PROPOSED * FACTORING	FACTP	0.000000	0.000000	0.000000
5	COS @ CLAIMED * AR REV REL TAX	REVFACC1	1.000000	1.000000	0.000000
6	COS @ CLAIMED * LA REV RELA TAX	REVFACC2	1.000000	0.000000	1.000000
7	COS @ CLAIMED * TX REV REL TAX	REVFACC3	1.000000	0.000000	1.000000
8	PROPOSED REV * AR REV REL TX	REVFACP1	1.000000	1.000000	0.000000
9	PROPOSED REV * LA REV REL TAX	REVFACP2	1.000000	0.000000	1.000000
10	PROPOSED REV * TX REV REL TAX	REVFACP3	1.000000	0.000000	1.000000
11	FUEL - RETAIL	FUELR	1.000000	0.216676	0.783324

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non- Arkansas) amounts on the the supporting schedules.

JURISDICTIONAL

		ALLOC	TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)
12	FUEL - WHOLESALE	FUELW	1.000000	0.000000	1.000000
13	SALES REVENUE - RETAIL	REVSALESR	1.000000	0.146555	0.853445
14	SALES REVENUE - WHOLESALE	REVSALESW	1.000000	0.000000	1.000000
15	SALES REVENUE - ARKANSAS	REVSALEAR	1.000000	1.000000	0.000000
16	SALES REVENUE - LOUISIANA	REVSALELA	1.000000	0.000000	1.000000
17	SALES REVENUE - TEXAS	REVSALETX	1.000000	0.000000	1.000000
18	PRODUCTION PLANT - TEXAS	PRODPLTTX	1.000000	0.000000	1.000000
19	DISTRIBUTION PLANT - LOUISIANA	DISTPLTLA	1.000000	0.000000	1.000000
20	RETAIL REVENUE LA	RREVLA	1.000000	0.000000	1.000000
21	TAXABLE INCOME LA	TAXINCLA	1.000000	0.000000	1.000000
22	TAXABLE INCOME AR	TAXINCAR	1.000000	1.000000	0.000000
23	PLANT LA	PLANTLA	1.000000	0.000000	1.000000
24	PLANT AR	PLANTAR	1.000000	1.000000	0.000000
25	DEMAND PROD WHOLESALE	DPRODWH	1.000000	0.000000	1.000000
26	DEMAND PROD ARKANSAS	DPRODAR	1.000000	1.000000	0.000000
27	DEMAND PROD LOUISIANA	DPRODLA	1.000000	0.000000	1.000000
28	DEMAND PROD TEXAS	DPRODTX	1.000000	0.000000	1.000000
29	DEMAND TRAN WHOLESALE	DTRANWH	1.000000	0.000000	1.000000
30	DEMAND TRAN ARKANSAS	DTRANAR	1.000000	1.000000	0.000000
31	DEMAND TRAN LOUISIANA	DTRANLA	1.000000	0.000000	1.000000
32	DEMAND TRAN TEXAS	DTRANTX	1.000000	0.000000	1.000000
33	DEMAND DIST WHOLESALE	DDISTWH	1.000000	0.000000	1.000000
34	DEMAND DIST ARKANSAS	DDISTAR	1.000000	1.000000	0.000000
35	DEMAND DIST LOUISIANA	DDISTLA	1.000000	0.000000	1.000000
36	DEMAND DIST TEXAS	DDISTTX	1.000000	0.000000	1.000000
37	DEMAND GENERAL WHOLESALE	DGENLWH	1.000000	0.000000	1.000000
38	DEMAND GENERAL ARKANSAS	DGENLAR	1.000000	1.000000	0.000000
39	DEMAND GENERAL LOUISIANA	DGENLLA	1.000000	0.000000	1.000000
40	DEMAND GENERAL TEXAS	DGENLTX	1.000000	0.000000	1.000000

INTERNALLY DEVELOPED (CON'T)

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Schedule: G-4
Development of Allocation Group
Jurisdiction

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward supporting schedules are at the Arkansas level and the Company is not reporting any non-Jurisdictional (non- Arkansas) amounts on the the supporting schedules.

JURISDICTIONAL

		ALLOC	TOTAL COMPANY (1)	AT ISSUE ARKANSAS RETAIL (2)	ALL OTHER (3)
1	PRODUCTION PLANT - TEXAS RETAIL	PRODPLTT	1.000000	0.000000	1.000000
2	LABOR 902 & 903	LAB902_903	1.000000	0.239381	0.760619
3	SALES REVENUE - AR RETAIL	RVSALEARR	1.000000	1.000000	0.000000
4	SALES REVENUE - LA RETAIL	RVSALELAR	1.000000	0.000000	1.000000
5	SALES REVENUE - TX RETAIL	RVSALETXR	1.000000	0.000000	1.000000
6	DIST PLANT BEFORE CONTRA ADJ	DISTPLTX	1.000000	0.198879	0.801121
7	STATE INCOME TAX	SIT	1.000000	(0.331874)	1.331874
8	RETAIL PRODUCTION PLANT	PRODPLTR	1.000000	0.216863	0.783137
9	TOTAL kWh AT GEN - ARKANSAS	KWHAR	1.000000	1.000000	0.000000
10	TOTAL kWh AT GEN- LOUISIANA	KWHLA	1.000000	0.000000	1.000000
11	TOTAL kWh AT GEN- TEXAS	KWHTX	1.000000	0.000000	1.000000
12	INTANGIBLE PLANT	INTPLT	1.000000	0.195411	0.804589
13	DEMPROD RETAIL	DEMRTAIL	1.000000	0.216863	0.783137
14	FIT TEMPORARY DIFFERENCES	FITTEMP	1.000000	0.196304	0.803696
15	Total Depr Expense	DEPEXP	1.000000	0.198123	0.801877
16	State Tax Calculated	STATETAXCALC	1.000000	(0.331874)	1.331874
17	Composite Tax Rate (FIT and AR State)	COMPTR	4.000000	1.000000	3.000000
18	Combined Tax Gross Up (FIT and AR State)	TAX GU	4.000000	1.000000	3.000000
19	FACTORING RATE	RFACT	4.000000	1.000000	3.000000
20	Gross Revenue Conversion Factor	REVCONV	4.000000	1.000000	3.000000
21	AVAILABLE	AVAIL	0.000000	0.000000	0.000000
22	AVAILABLE	AVAIL	0.000000	0.000000	0.000000

Supporting Schedules
(a) G-5.1 or G-5.2
(b) H-1
WP's G-2
WP's G-2 and G-3
G Juris WP

Recap Schedules
(A) G-2, G-3

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
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Explanation. Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	TOTAL AR RETAIL JURISDICTION (1)	RESIDENTIAL (2)	COMMERCIAL / SMALL INDUSTRIAL (3)	LARGE INDUSTRIAL (4)	MUNICIPAL (5)	LIGHTING (6)
SCHEDULE G-4 ALLOCATION FACTOR TABLE CAPACITY RELATED							
1 PRODUCTION ALLOCATOR	DEMPROD	1.00000	0.40327	0.48140	0.10580	0.00422	0.00531
2							
3 TRANSMISSION FUNCTION	DEMTRANS	1.00000	0.38761	0.48504	0.12235	0.00480	0.00020
4 D. A. ACCT 360 - LAND (MDO)	DEM360DA	984,313	421,055	491,093	53,048	5,567	13,550
5 D. A. ACCT 361 - STRUCTURES & IMPROVE	DEM361DA	984,313	421,055	491,093	53,048	5,567	13,550
6 D. A. ACCT 362 - STATION EQUIPMENT	DEM362DA	984,313	421,055	491,093	53,048	5,567	13,550
7 D. A. ACCT 364 - PRI POLES, TOWERS & FIX	DEM364DAP	984,313	421,055	491,093	53,048	5,567	13,550
8 D. A. ACCT 364 - SEC POLES, TOWERS & FIX	DEM364DAS	826,390	421,055	386,218	0	5,567	13,550
9 D. A. ACCT 365 - PRI - OVRHD COND & DEVICES	DEM365DAP	984,313	421,055	491,093	53,048	5,567	13,550
10 D. A. ACCT 365 - SEC - OVRHD COND & DEVICES	DEM365DAS	826,390	421,055	386,218	0	5,567	13,550
11 D. A. ACCT 366 - PRI - UNDERGROUND CONDUIT	DEM366DAP	984,313	421,055	491,093	53,048	5,567	13,550
12 D. A. ACCT 366 - SEC- UNDERGROUND CONDUIT	DEM366DAS	826,390	421,055	386,218	0	5,567	13,550
13 D. A. ACCT 367 - PRI - UNDGRD COND & DEVICE	DEM367DAP	984,313	421,055	491,093	53,048	5,567	13,550
14 D. A. ACCT 367 - SEC - UNDGRD COND & DEVICE	DEM367DAS	826,390	421,055	386,218	0	5,567	13,550
15 D. A. ACCT 368 - LINE TRANSORMERS	DEM368DA	984,313	421,055	491,093	53,048	5,567	13,550
16 ANNUAL BILLING DEMAND	DEM99	6,810,824	83,753	5,378,433	1,244,525	104,113	0
17 SPP DEMAND	SPPDEMAND	1.00000	0.38761	0.48504	0.12235	0.00480	0.00020
18 AVAILABLE SUBSTATIONS	USERSUB	0	0	0	0	0	-
19 AVAILABLE DIR ASSIGN SUBS	USERDASUB	0	0	0	0	0	-
20 AVAILABLE-PRI OVHD	USEROVHD	0	0	0	0	0	-
21 AVAILABLE SECONDARY	USERSEC	0	0	0	0	0	-
22							
23							
24							
25 COMMODITY RELATED							
26							
27 FUEL ALLOCATION	FUEL	120,462,364	36,022,303	63,986,039	18,588,171	656,991	1,208,860
28 KWH SALES AT GENERATOR	ENERGY	4,130,615,297	1,249,158,554	2,191,474,387	625,702,479	23,037,208	41,242,668
29 SALES OF ELECTRICITY - PRESENT FUEL	REVFUEL	-	-	-	-	-	-
30 KWH SALES AT METER	ENERGY99	3,867,122,238	1,157,861,199	2,046,621,378	603,057,813	21,353,486	38,228,362
31 MINE CLOSING	MINECLOSE	0	0	0	0	0	-
32 MINE CLOSING NFIRM RETAIL	MINECLOSEN	0	0	0	0	0	-
33 NON FIRM FUEL PRESENT FUEL	NFREVFUEL	0	0	0	0	0	0
34 FUEL ADJUSTMENT	FUELADJ	0	0	0	0	0	0
35 NON FIRM PROPOSED FUEL RETAIL	NFPROPFUEL	0	0	0	0	0	0
36 PROPOSED FUEL REVENUE	PROPFUEL	0	0	0	0	0	0
SCHEDULE G-4 CUSTOMER RELATED							
1 ANNUAL AVERAGE CUSTOMERS	CUST99	150,754	101,505	17,779	9	754	30,707
2 YEAR END NUMBER OF CUSTOMERS	CUST	150,754	101,505	17,779	9	754	30,707
3 WEIGHTED SERVICES	CUST369	124,610	101,504	22,100	21	965	-
4 WEIGHTED METERS	CUST370	153,057	101,469	48,774	1,290	1,524	-
5 ASSIGNED CUSTOMER INSTALLATIONS	CUST371L	17,217	-	-	-	-	17,217
6 LIGHTING ASSIGNMENTS	CUST373	13,661	-	-	-	-	13,661
7 WEIGHTED METERS	CUST902	126,340	101,504	23,814	11	1,011	-
8 CUSTOMER ACCOUNTING	CUST903	132,937	101,505	20,092	10,390	754	186
9 CUSTOMER INFO EXP ALLOC	CUSTINFO	150,754	101,505	17,779	9	754	30,707
10 CUSTOMER SERVICE EXP ALLOC	CUSTSRVC	150,754	101,505	17,779	9	754	30,707
11 ACTIVE CUSTOMER DEPOSITS	CUSTDEPA	-	-	-	-	-	-
12 CUSTOMERS IN AR & LA	CUSTARLA	150,754	101,505	17,779	9	754	30,707
13 RETAIL CUSTOMERS	CUSTRET	150,754	101,505	17,779	9	754	30,707
14 AVAILABLE-SERVICE DROP	CUSER1	-	-	-	-	-	-
15 AVAILABLE-SERVICE DROP	CUSER2	-	-	-	-	-	-
16 AVAILABLE-METERS	CUSER3	-	-	-	-	-	-

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	TOTAL AR RETAIL JURISDICTION (1)	RESIDENTIAL (2)	COMMERCIAL / SMALL INDUSTRIAL (3)	LARGE INDUSTRIAL (4)	MUNICIPAL (5)	LIGHTING (6)
17 AVAILABLE-METERS	CUSER4	-	-	-	-	-	-
18 AVAILABLE-CUSTOMER SERVICES	CUSER5	126,340	101,504	23,814	11	1,011	-
19 AVAILABLE-CUSTOMER SERVICES	CUSER6	-	-	-	-	-	-
20 CUSTOMER ENERGY SPLIT 907-916	CUSER7	1.00000	0.48636	0.32358	0.07800	0.00526	0.10679
21 AVAILABLE-CUSTOMER BILLING	CUSER8	-	-	-	-	-	-
22 AVAILABLE-CUSTOMER BILLING	CUSER9	1	1	0	0	0	0
23 AVAILABLE-CUSTOMER LTG AND MISC REV	CUSER10	-	-	-	-	-	-
24 AVAILABLE-CUSTOMER LTG AND MISC REV	CUSER11	-	-	-	-	-	-
25 AVAILABLE-CUSTOMER OTHER	CUSER12	-	-	-	-	-	-
26							
27 REVENUE RELATED STRINGS							
28 ------------------------------							
29 SALES OF ELECTRICITY-BASE	R40B	129,184,908	53,645,062	59,079,104	11,148,764	753,656	4,558,322
30 GROSS RECEIPTS FACTOR	RGR	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
31 CLAIMED RATE OF RETURN	ROR	0.0521	0.0521	0.0521	0.0521	0.0521	0.0521
32 CLAIMED FACTORING	RFACT	0.003205	0.008613	0.000460	0.000090	0.000000	0.000000
33 PROPOSED REVENUES	PREV	203,711,789	85,321,541	95,875,234	18,031,502	1,036,089	3,447,422
34 FEDERAL INCOME TAX RATE		0.21000	0.21000	0.21000	0.21000	0.21000	0.21000
35 LOUISIANA APPORTIONMENT FACTOR		0.24386	0.24386	0.24386	0.24386	0.24386	0.24386
36 LOUISIANA INCOME TAX RATE		0.06500	0.06500	0.06500	0.06500	0.06500	0.06500
37 ARKANSAS APPORTIONMENT FACTOR		0.24386	0.24386	0.24386	0.24386	0.24386	0.24386
38 ARKANSAS INCOME TAX RATE		0.06500	0.06500	0.06500	0.06500	0.06500	0.06500
SCHEDULE G-4							
INTERNALLY DEVELOPED							
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1 PRODUCTION PLANT	PRODPLT	609,249,318	245,690,263	293,294,472	64,459,058	2,570,418	3,235,107
2 PLANT ACCOUNT 352	PLT352	3,372,745	1,307,322	1,635,913	412,641	16,191	678
3 PLANT ACCOUNT 353	PLT353	140,243,262	54,360,180	68,023,470	17,158,176	673,255	28,180
4 PLANT ACCOUNTS 352 & 353	TRANSUB	143,616,007	55,667,502	69,659,384	17,570,818	689,447	28,858
5 PLANT ACCOUNTS 354, 355 & 356	TRANOHLN	244,914,354	94,932,107	118,793,046	29,964,246	1,175,742	49,212
6 PLANT ACCOUNT 357	TRANUGLN	474,192	183,803	230,002	58,015	2,276	95
7 TRANSMISSION PLANT	TRANPLT	411,407,560	159,467,120	199,548,767	50,333,993	1,975,014	82,666
8 PROD. & TRANS. PLANT	PTPLT	1,020,656,879	405,157,383	492,843,239	114,793,052	4,545,432	3,317,774
9 PLANT ACCOUNT 361	PLT361	2,518,993	1,077,537	1,256,775	135,757	14,247	34,677
10 PLANT ACCOUNT 362	PLT362	80,952,717	34,628,734	40,388,896	4,362,827	457,847	1,114,413
11 PLANT ACCOUNT 368	PLT368	59,647,952	25,515,303	29,759,531	3,214,638	337,353	821,127
12 PLANT ACCOUNT 370	PLT370	18,544,958	12,294,363	5,909,640	156,301	184,654	-
13 PLANT ACCOUNT 371	PLT371	8,327,075	-	-	-	-	8,327,075
14 PLANT ACCOUNT 373	PLT373	7,510,701	-	-	-	-	7,510,701
15 PLANT ACCOUNT 361 & 362	DISTSUB	83,471,710	35,706,271	41,645,671	4,498,584	472,094	1,149,090
16 PLANT ACCOUNT 364 & 365	DISTOHLN	185,060,700	84,160,784	90,400,442	6,678,295	1,112,740	2,708,441
17 PLANT ACCOUNT 366 & 367	DISTUGLN	74,097,249	34,894,387	35,733,673	1,884,867	461,359	1,122,962
18 DISTRIBUTION PLANT	DISTPLT	460,470,865	211,157,575	208,359,682	16,559,117	2,751,607	21,642,885
19 TRANS. & DISTR. PLANT	TDPLT	871,878,425	370,624,695	407,908,448	66,893,110	4,726,621	21,725,551
20 PROD., TRANS., & DISTR. PLANT	PTDPLT	1,481,127,744	616,314,957	701,202,921	131,352,168	7,297,038	24,960,659
21 GENERAL PLANT EXCL ADJUSTMENTS	GENPLTX	61,126,719	22,134,671	30,652,399	7,606,687	291,773	441,189
22 GENERAL PLANT	GENPLT	61,126,719	22,134,671	30,652,399	7,606,687	291,773	441,189
23 TOTAL ELECTRIC PLANT IN SERVICE	PLANT	1,573,040,891	650,806,372	746,528,669	141,566,516	7,749,883	26,389,452
24 NET PLANT IN SERVICE	NETPLT	1,005,390,167	418,124,763	475,806,644	87,898,841	5,053,917	18,506,001
25 RATE BASE	RBX	1,181,137,178	490,728,678	558,405,252	104,233,350	5,951,260	21,818,638
26 OPERATING EXPENSE ACCT NO. 500	OX500	3,445,742	1,326,272	1,689,626	393,224	15,390	21,230
27 OPERATING EXPENSE ACCT NO. 501	OX501	3,413,437	1,032,273	1,810,980	517,065	19,037	34,082
28 OPERATING EXPENSE ACCT NO. 502	OX502	3,030,422	1,222,070	1,458,854	320,621	12,785	16,092
29 OPERATING EXPENSE ACCT NO. 505	OX505	1,184,824	477,801	570,378	125,355	4,999	6,291
30 OPERATING EXPENSE ACCT NO. 506	OX506	4,032,566	1,626,202	1,941,290	426,649	17,013	21,413
31 MAINTENANCE EXPENSE ACCT NO. 510	MX510	937,255	292,940	492,626	137,672	5,099	8,918
32 MAINTENANCE EXPENSE ACCT NO. 511	MX511	551,702	222,484	265,591	58,371	2,328	2,930
33 MAINTENANCE EXPENSE ACCT NO. 512	MX512	8,058,769	2,437,090	4,275,534	1,220,736	44,945	80,464
34 MAINTENANCE EXPENSE ACCT NO. 513	MX513	982,297	297,061	521,152	148,798	5,478	9,808

SOUTHWESTERN ELECTRIC POWER COMPANY
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Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross refereneces to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	TOTAL AR RETAIL JURISDICTION (1)	RESIDENTIAL (2)	COMMERCIAL / SMALL INDUSTRIAL (3)	LARGE INDUSTRIAL (4)	MUNICIPAL (5)	LIGHTING (6)
35 MAINTENANCE EXPENSE ACCT NO. 514	MX514	798,311	321,933	384,309	84,462	3,368	4,239
36 OPERATING EXPENSE ACCT NO. 546	OX546	-	-	-	-	-	-
37 OPERATING EXPENSE ACCT NO. 548	OX548	123,588	49,839	59,496	13,076	521	656
38 OPERATING EXPENSE ACCT NO. 549	OX549	-	-	-	-	-	-
39 MAINTENANCE EXPENSE ACCT NO. 551	MX551	-	-	-	-	-	-
40 MAINTENANCE EXPENSE ACCT NO. 552	MX552	-	-	-	-	-	-
SCHEDULE G-4							
INTERNALLY DEVELOPED (CON'T)							
1 MAINTENANCE EXPENSE ACCT NO. 553	MX553	123,245	49,701	59,331	13,039	520	654
2 MAINTENANCE EXPENSE ACCT NO. 554	MX554	3,296	1,329	1,587	349	14	18
3 OPERATING EXPENSE ACCT NO. 556	OX556	373,748	150,720	179,924	39,543	1,577	1,985
4 OPERATING EXPENSE ACCT NO. 557	OX557	718,161	289,611	345,725	75,982	3,030	3,813
5 OPERATING EXPENSE ACCT NO. 560	OX560	1,517,917	588,365	736,249	185,711	7,287	305
6 OPERATING EXPENSE ACCT NO. 561	OX561	2,929,021	1,135,328	1,420,690	358,353	14,061	589
7 OPERATING EXPENSE ACCT NO. 562	OX562	109,747	42,539	53,232	13,427	527	22
8 OPERATING EXPENSE ACCT NO. 563	OX563	86,612	33,572	42,010	10,597	416	17
9 OPERATING EXPENSE ACCT NO. 564	OX564	-	-	-	-	-	-
10 OPERATING EXPENSE ACCT NO. 565	OX565	21,587,502	8,367,607	10,470,783	2,641,141	103,634	4,338
11 OPERATING EXPENSE ACCT NO. 566	OX566	399,598	154,890	193,821	48,889	1,918	80
12 MAINTENANCE EXPENSE ACCT NO. 568	MX568	8,401	3,256	4,075	1,028	40	2
13 MAINTENANCE EXPENSE ACCT NO. 569	MX569	117,056	45,373	56,777	14,321	562	24
14 MAINTENANCE EXPENSE ACCT NO. 570	MX570	718,780	278,609	348,636	87,940	3,451	144
15 MAINTENANCE EXPENSE ACCT NO. 571	MX571	2,108,982	817,470	1,022,939	258,025	10,124	424
16 MAINTENANCE EXPENSE ACCT NO. 572	MX572	194	75	94	24	1	0
17 MAINTENANCE EXPENSE ACCT NO. 573	MX573	7,844	3,040	3,804	960	38	2
18 OPERATING EXPENSE ACCT NO. 580	OX580	482,490	232,188	204,185	14,150	3,143	28,824
19 OPERATING EXPENSE ACCT NO. 581	OX581	6,270	2,875	2,837	225	37	295
20 OPERATING EXPENSE ACCT NO. 582	OX582	103,510	44,278	51,643	5,579	585	1,425
21 OPERATING EXPENSE ACCT NO. 583	OX583	602,750	274,115	294,438	21,751	3,624	8,821
22 OPERATING EXPENSE ACCT NO. 584	OX584	508,483	239,458	245,218	12,935	3,166	7,706
23 OPERATING EXPENSE ACCT NO. 585	OX585	33,345	-	-	-	-	33,345
24 OPERATING EXPENSE ACCT NO. 586	OX586	698,380	462,990	222,550	5,886	6,954	-
25 OPERATING EXPENSE ACCT NO. 587	OX587	126,372	-	-	-	-	126,372
26 OPERATING EXPENSE ACCT NO. 588	OX588	3,814,525	1,749,222	1,726,044	137,175	22,794	179,289
27 OPERATING EXPENSE ACCT NO. 589	OX589	177,357	81,330	80,253	6,378	1,060	8,336
28 MAINTENANCE EXPENSE ACCT NO. 590	MX590	72,853	32,411	33,395	2,415	433	4,199
29 MAINTENANCE EXPENSE ACCT NO. 591	MX591	6,709	2,870	3,347	362	38	92
30 MAINTENANCE EXPENSE ACCT NO. 592	MX592	165,128	70,636	82,386	8,899	934	2,273
31 MAINTENANCE EXPENSE ACCT NO. 593	MX593	4,806,467	2,185,856	2,347,915	173,451	28,901	70,345
32 MAINTENANCE EXPENSE ACCT NO. 594	MX594	242,338	114,124	116,869	6,165	1,509	3,673
33 MAINTENANCE EXPENSE ACCT NO. 595	MX595	19,704	8,429	9,831	1,062	111	271
34 MAINTENANCE EXPENSE ACCT NO. 596	MX596	64,412	-	-	-	-	64,412
35 MAINTENANCE EXPENSE ACCT NO. 597	MX597	96,081	63,697	30,618	810	957	-
36 MAINTENANCE EXPENSE ACCT NO. 598	MX598	43,021	-	-	-	-	43,021
37 OPERATING EXPENSE ACCT NO. 901	OX901	162,910	127,583	24,065	10,145	925	191
38 OPERATING EXPENSE ACCT NO. 902	OX902	480,793	386,278	90,625	42	3,847	-
39 OPERATING EXPENSE ACCT NO. 903	OX903	4,065,728	3,170,119	572,491	296,048	21,486	5,585
40 OPERATING EXPENSE ACCT NO. 904	OX904	348,857	144,866	159,540	30,107	2,035	12,310
SCHEDULE G-4							
INTERNALLY DEVELOPED (CON'T)							
1 OPERATING EXPENSE ACCT NO. 905	OX905	25,304	19,817	3,738	1,576	144	30
2 OPERATING EXPENSE ACCT NO. 907	OX907	218,846	106,439	70,815	17,070	1,152	23,370
3 OPERATING EXPENSE ACCT NO. 908	OX908	758,779	369,042	245,530	59,187	3,993	81,028
4 OPERATING EXPENSE ACCT NO. 909	OX909	3,146	1,530	1,018	245	17	336
5 OPERATING EXPENSE ACCT NO. 910	OX910	1,860	905	602	145	10	199
6 OPERATING EXPENSE ACCT NO. 911	OX911	70	34	23	5	0	7

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Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	TOTAL AR RETAIL JURISDICTION	RESIDENTIAL	COMMERCIAL / SMALL INDUSTRIAL	LARGE INDUSTRIAL	MUNICIPAL	LIGHTING
		(1)	(2)	(3)	(4)	(5)	(6)
7 OPERATING EXPENSE ACCT NO. 912	OX912	36,201	17,607	11,714	2,824	190	3,866
8 OPERATING EXPENSE ACCT NO. 913	OX913	(4,878)	(2,372)	(1,578)	(380)	(26)	(521)
9 OPERATING EXPENSE ACCT NO. 916	OX916	-	-	-	-	-	-
10 OPERATING EXPENSE ACCT NO. 920	OX920	6,926,902	3,105,760	2,983,984	626,023	36,600	174,535
11 OPERATING EXPENSE ACCT NO. 921	OX921	504,340	226,127	217,261	45,580	2,665	12,708
12 OPERATING EXPENSE ACCT NO. 922	OX922	(743,649)	(333,424)	(320,350)	(67,208)	(3,929)	(18,737)
13 OPERATING EXPENSE ACCT NO. 923	OX923	3,560,659	1,596,465	1,533,867	321,797	18,814	89,717
14 1/8 O&M LESS FUEL & PURCHASED PWR	OMX	11,387,376	4,815,182	5,201,625	1,136,607	58,567	175,395
15 DEPRECIATION EXPENSE	DEPREXP	42,372,026	17,659,091	20,054,029	3,695,359	209,192	754,355
16 AD VALOREM TAXES	PROPTAX	12,366,538	5,116,346	5,868,872	1,112,932	60,926	207,462
17 LABOR ACCOUNTS 501 THRU 507	LAB501_507	3,603,491	1,386,990	1,766,978	411,227	16,094	22,202
18 LABOR ACCOUNTS 511 THRU 514	LAB511_514	2,713,683	848,164	1,426,326	398,608	14,764	25,820
19 LABOR ACCOUNTS 547 THRU 550	LAB547_550	64,062	25,834	30,840	6,778	270	340
20 LABOR ACCOUNTS 552 THRU 554	LAB552_554	35,727	14,408	17,199	3,780	151	190
21 LABOR ACCOUNTS 561 THRU 567	LAB561_567	374,443	145,139	181,619	45,812	1,798	75
22 LABOR ACCOUNTS 569 THRU 573	LAB569_573	595,193	230,705	288,692	72,819	2,857	120
23 LABOR ACCOUNTS 581 THRU 589	LAB581_589	3,222,491	1,550,753	1,363,725	94,507	20,994	192,512
24 LABOR ACCOUNTS 591 THRU 598	LAB591_598	1,597,251	710,579	732,165	52,951	9,490	92,066
25 LABOR ACCOUNTS 902 THRU 905	LAB902_905	2,283,046	1,787,974	337,253	142,173	12,964	2,681
26 LABOR ACCOUNTS 908 THRU 910	LAB908_910	747,817	363,711	241,982	58,331	3,935	79,857
27 LABOR ACCOUNTS 912 THRU 916	LAB912_916	168	82	54	13	1	18
28 PAYROLL EXCLUDING A&G	LABORX	20,001,234	8,994,617	8,604,064	1,801,260	106,243	495,050
29 RETAIL PAYROLL EXCLUDING A&G	LABORXR	20,001,234	8,994,617	8,604,064	1,801,260	106,243	495,050
30 TOTAL PAYROLL	LABORT	23,811,930	10,676,367	10,257,748	2,152,019	125,816	599,981
31 ACCT 903 EXCL BILLING	OX903X	-	-	-	-	-	-
32 ACCT 903 BILLING	OX903B	4,065,728	3,170,119	572,491	296,048	21,486	5,585
33 PRODUCTION LABOR	LABPROD	9,553,314	3,459,362	4,790,572	1,188,827	45,600	68,952
34 TRANSMISSION LABOR	LABTRAN	1,780,652	690,205	863,686	217,855	8,548	358
35 DISTR LABOR EXCL METERING	LABDIST	4,499,967	1,990,267	2,028,786	151,536	26,188	303,191
36 CUST SERVICE LABOR EXCL METER & BILLING	LABCUSSV	3,203,616	2,169,507	656,927	237,676	16,957	122,550
37 METERING LABOR	LABMETER	963,684	685,276	264,092	5,367	8,950	-
38 BILLING LABOR	LABBILL	-	-	-	-	-	-

SCHEDULE G-4
INTERNALLY DEVELOPED (CON'T)

	ALLOC	TOTAL AR RETAIL JURISDICTION	RESIDENTIAL	COMMERCIAL / SMALL INDUSTRIAL	LARGE INDUSTRIAL	MUNICIPAL	LIGHTING
1 SALES REVENUE	REVSALES	129,184,908	53,645,062	59,079,104	11,148,764	753,656	4,558,322
2 0.5*PRODPLT + 0.95*TDPLT	PTDPLTW	1,132,909,163	474,938,591	534,160,262	95,777,984	5,775,499	22,256,827
3 REV DEF @ CLAIMED * FACTORING	FACTC	-	-	-	-	-	-
4 REV DEF @ PROPOSED * FACTORING	FACTP	-	-	-	-	-	-
5 COS @ CLAIMED * AR REV REL TAX	REVFACC1	15	2	5	4	2	2
6 COS @ CLAIMED * LA REV RELA TAX	REVFACC2	-	-	-	-	-	-
7 COS @ CLAIMED * TX REV REL TAX	REVFACC3	-	-	-	-	-	-
8 PROPOSED REV * AR REV REL TX	REVFACP1	15	2	5	4	2	2
9 PROPOSED REV * LA REV REL TAX	REVFACP2	-	-	-	-	-	-
10 PROPOSED REV * TX REV REL TAX	REVFACP3	-	-	-	-	-	-
11 FUEL - RETAIL	FUELR	3,413,437	1,032,273	1,810,980	517,065	19,037	34,082
12 FUEL - WHOLESALE	FUELW	-	-	-	-	-	-
13 SALES REVENUE - RETAIL	REVSALESR	129,184,908	53,645,062	59,079,104	11,148,764	753,656	4,558,322
14 SALES REVENUE - WHOLESALE	REVSALESW	-	-	-	-	-	-
15 SALES REVENUE - ARKANSAS	REVSALEAR	129,184,908	53,645,062	59,079,104	11,148,764	753,656	4,558,322
16 SALES REVENUE - LOUISIANA	REVSALELA	-	-	-	-	-	-
17 SALES REVENUE - TEXAS	REVSALETX	-	-	-	-	-	-
18 PRODUCTION PLANT - TEXAS	PRODPLTTX	-	-	-	-	-	-
19 DISTRIBUTION PLANT - LOUISIANA	DISTPLTLA	-	-	-	-	-	-
20 RETAIL REVENUE LA	RREVLA	-	-	-	-	-	-
21 TAXABLE INCOME LA	TAXINCLA	-	-	-	-	-	-
22 TAXABLE INCOME AR	TAXINCAR	(31,845,328)	(13,384,027)	(16,212,146)	(4,046,863)	(71,994)	1,869,701

SOUTHWESTERN ELECTRIC POWER COMPANY
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Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	TOTAL AR RETAIL JURISDICTION (1)	RESIDENTIAL (2)	COMMERCIAL / SMALL INDUSTRIAL (3)	LARGE INDUSTRIAL (4)	MUNICIPAL (5)	LIGHTING (6)
23 PLANT LA	PLANTLA	-	-	-	-	-	-
24 PLANT AR	PLANTAR	1,573,040,891	650,806,372	746,528,669	141,566,516	7,749,883	26,389,452
25 DEMAND PROD WHOLESALE	DPRODWH	-	-	-	-	-	-
26 DEMAND PROD ARKANSAS	DPRODAR	600,667,049	242,229,315	289,162,942	63,551,047	2,534,209	3,189,536
27 DEMAND PROD LOUISIANA	DPRODLA	-	-	-	-	-	-
28 DEMAND PROD TEXAS	DPRODTX	-	-	-	-	-	-
29 DEMAND TRAN WHOLESALE	DTRANWH	-	-	-	-	-	-
30 DEMAND TRAN ARKANSAS	DTRANAR	411,230,169	159,398,361	199,462,725	50,312,290	1,974,162	82,631
31 DEMAND TRAN LOUISIANA	DTRANLA	-	-	-	-	-	-
32 DEMAND TRAN TEXAS	DTRANTX	-	-	-	-	-	-
33 DEMAND DIST WHOLESALE	DDISTWH	-	-	-	-	-	-
34 DEMAND DIST ARKANSAS	DDISTAR	461,207,803	211,495,512	208,693,141	16,585,618	2,756,011	21,677,522
35 DEMAND DIST LOUISIANA	DDISTLA	-	-	-	-	-	-
36 DEMAND DIST TEXAS	DDISTTX	-	-	-	-	-	-
37 DEMAND GENERAL WHOLESALE	DGENLWH	-	-	-	-	-	-
38 DEMAND GENERAL ARKANSAS	DGENLAR	61,126,719	22,134,671	30,652,399	7,606,687	291,773	441,189
39 DEMAND GENERAL LOUISIANA	DGENLLA	-	-	-	-	-	-
40 DEMAND GENERAL TEXAS	DGENLTX	0	0	0	0	0	0

SCHEDULE G-4
INTERNALLY DEVELOPED (CON'T)

	ALLOC	TOTAL AR RETAIL JURISDICTION (1)	RESIDENTIAL (2)	COMMERCIAL / SMALL INDUSTRIAL (3)	LARGE INDUSTRIAL (4)	MUNICIPAL (5)	LIGHTING (6)
1 PRODUCTION PLANT - TEXAS RETAIL	PRODPLTT	-	-	-	-	-	-
2 LABOR 902 & 903	LAB902_903	2,278,948	1,784,765	336,648	141,918	12,941	2,677
3 SALES REVENUE - AR RETAIL	RVSALEARR	129,184,908	53,645,062	59,079,104	11,148,764	753,656	4,558,322
4 SALES REVENUE - LA RETAIL	RVSALELAR	-	-	-	-	-	-
5 SALES REVENUE - TX RETAIL	RVSALETXR	-	-	-	-	-	-
6 DIST PLANT BEFORE CONTRA ADJ	DISTPLTX	461,207,803	211,495,512	208,693,141	16,585,618	2,756,011	21,677,522
7 STATE INCOME TAX	SIT	(1,040,062)	(436,806)	(527,834)	(130,396)	(2,479)	57,452
8 RETAIL PRODUCTION PLANT	PRODPLTR	609,249,318	245,690,263	293,294,472	64,459,058	2,570,418	3,235,107
9 TOTAL kWh AT GEN - ARKANSAS	KWHAR	4,130,615,297	1,249,158,554	2,191,474,387	625,702,479	23,037,208	41,242,668
10 TOTAL kWh AT GEN- LOUISIANA	KWHLA	-	-	-	-	-	-
11 TOTAL kWh AT GEN- TEXAS	KWHTX	-	-	-	-	-	-
12 INTANGIBLE PLANT	INTPLT	30,786,428	12,356,744	14,673,349	2,607,660	161,071	987,604
13 DEMPROD RETAIL	DEMRTAIL	1.0000	0.4033	0.4814	0.1058	0.0042	0.0053
14 FIT TEMPORARY DIFFERENCES	FITTEMP	(11,028,177)	(4,467,073)	(5,268,588)	(1,064,703)	(54,688)	(173,125)
15 Total Depr Expense	DEPEXP	42,372,026	17,659,091	20,054,029	3,695,359	209,192	754,356
16 AVAILABLE	AVAIL	0	0	0	0	0	0
17 Composite Tax Rate (FIT and AR State)	COMPTR	26.1350%	26.1350%	26.1350%	26.1350%	26.1350%	26.1350%
18 Combined Tax Gross Up (FIT and AR State)	TAX GU	35.3821%	35.3821%	35.3821%	35.3821%	35.3821%	35.3821%
19 CLAIMED FACTORING	RFACT	0.3205%	0.008613	0.000460	0.000090	0.000000	0.000000
20 Gross Revenue Conversion Factor	REVCONV	1.358174	1.365583	1.354444	1.353943	1.353821	1.353821
21 AVAILABLE	AVAIL	0	0	0	0	0	0

SCHEDULE G-4
RATIO TABLE
CAPACITY RELATED

	ALLOC	TOTAL AR RETAIL JURISDICTION (1)	RESIDENTIAL (2)	COMMERCIAL / SMALL INDUSTRIAL (3)	LARGE INDUSTRIAL (4)	MUNICIPAL (5)	LIGHTING (6)
1 PRODUCTION ALLOCATOR	DEMPROD	1.000000	0.40327	0.48140	0.10580	0.00422	0.00531
2							
3 TRANSMISSION FUNCTION	DEMTRANS	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020
4 D. A. ACCT 360 - LAND (MDD)	DEM360DA	1.000000	0.42776	0.49892	0.05389	0.00566	0.01377
5 D. A. ACCT 361 - STRUCTURES & IMPROVE	DEM361DA	1.000000	0.42776	0.49892	0.05389	0.00566	0.01377
6 D. A. ACCT 362 - STATION EQUIPMENT	DEM362DA	1.000000	0.42776	0.49892	0.05389	0.00566	0.01377
7 D. A. ACCT 364 - PRI POLES, TOWERS & FIX	DEM364DAP	1.000000	0.42776	0.49892	0.05389	0.00566	0.01377
8 D. A. ACCT 364 - SEC POLES, TOWERS & FIX	DEM364DAS	1.000000	0.50951	0.46736	-	0.00674	0.01640
9 D. A. ACCT 365 - PRI - OVRHD COND & DEVICES	DEM365DAP	1.000000	0.42776	0.49892	0.05389	0.00566	0.01377
10 D. A. ACCT 365 - SEC - OVRHD COND & DEVICES	DEM365DAS	1.000000	0.50951	0.46736	-	0.00674	0.01640
11 D. A. ACCT 366 - PRI - UNDERGROUND CONDUIT	DEM366DAP	1.000000	0.42776	0.49892	0.05389	0.00566	0.01377
12 D. A. ACCT 366 - SEC- UNDERGROUND CONDUIT	DEM366DAS	1.000000	0.50951	0.46736	-	0.00674	0.01640
13 D. A. ACCT 367 - PRI - UNDGRD COND & DEVICE	DEM367DAP	1.000000	0.42776	0.49892	0.05389	0.00566	0.01377

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	TOTAL AR RETAIL JURISDICTION	RESIDENTIAL	COMMERCIAL / SMALL INDUSTRIAL	LARGE INDUSTRIAL	MUNICIPAL	LIGHTING
		(1)	(2)	(3)	(4)	(5)	(6)
14 D. A. ACCT 367 - SEC - UNDGRD COND & DEVICE	DEM367DAS	1.000000	0.50951	0.46736	-	0.00674	0.01640
15 D. A. ACCT 368 - LINE TRANSORMERS	DEM368DA	1.000000	0.42776	0.49892	0.05389	0.00566	0.01377
16 ANNUAL BILLING DEMAND	DEM99	1.000000	0.01230	0.78969	0.18273	0.01529	-
17 SPP DEMAND	SPPDEMAND	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020
18 AVAILABLE-SUBSTATIONS	USERSUB	0.000000	-	-	-	-	-
19 AVAILABLE-DIR ASSIGN SUBS	USERDASUB	0.000000	-	-	-	-	-
20 AVAILABLE-PRI OVHD	USEROVHD	0.000000	-	-	-	-	-
21 AVAILABLE-SECONDARY	USERSEC	0.000000	-	-	-	-	-
22							
23							
24							
25 COMMODITY RELATED							
26 ------------------------------------							
27 FUEL ALLOCATION	FUEL	1.000000	0.29903	0.53117	0.15431	0.00545	0.01004
28 KWH SALES AT GENERATOR	ENERGY	1.000000	0.30241	0.53054	0.15148	0.00558	0.00998
29 SALES OF ELECTRICITY - PRESENT FUEL	REVFUEL	0.000000	-	-	-	-	-
30 KWH SALES AT METER	ENERGY99	1.000000	0.29941	0.52924	0.15594	0.00552	0.00989
31 MINE CLOSING	MINECLOSE	0.000000	-	-	-	-	-
32 MINE CLOSING NFIRM RETAIL	MINECLOSEN	0.000000	-	-	-	-	-
33 NON FIRM FUEL PRESENT FUEL	NFREVFUEL	0.000000	-	-	-	-	-
34 FUEL ADJUSTMENT	FUELADJ	0.000000	-	-	-	-	-
35 NON FIRM PROPOSED FUEL RETAIL	NFPROPFUEL	0.000000	-	-	-	-	-
36 PROPOSED FUEL REVENUE	PROPFUEL	0.000000	-	-	-	-	-
SCHEDULE G-4							
CUSTOMER RELATED							
------------------------------------							
1 ANNUAL AVERAGE CUSTOMERS	CUST99	1.000000	0.67332	0.11793	0.00006	0.00500	0.20369
2 YEAR END NUMBER OF CUSTOMERS	CUST	1.000000	0.67332	0.11793	0.00006	0.00500	0.20369
3 WEIGHTED SERVICES	CUST369	1.000000	0.81457	0.17735	0.00017	0.00790	-
4 WEIGHTED METERS	CUST370	1.000000	0.66295	0.31867	0.00843	0.00996	-
5 ASSIGNED CUSTOMER INSTALLATIONS	CUST371L	1.000000	-	-	-	-	1.00000
6 LIGHTING ASSIGNMENTS	CUST373	1.000000	-	-	-	-	1.00000
7 WEIGHTED METERS	CUST902	1.000000	0.80342	0.18849	0.00009	0.00800	-
8 CUSTOMER ACCOUNTING	CUST903	1.000000	0.76355	0.15114	0.07816	0.00567	0.00147
9 CUSTOMER INFO EXP ALLOC	CUSTINFO	1.000000	0.67332	0.11793	0.00006	0.00500	0.20369
10 CUSTOMER SERVICE EXP ALLOC	CUSTSRVC	1.000000	0.67332	0.11793	0.00006	0.00500	0.20369
11 ACTIVE CUSTOMER DEPOSITS	CUSTDEPA	0.000000	-	-	-	-	-
12 CUSTOMERS IN AR & LA	CUSTARLA	1.000000	0.67332	0.11793	0.00006	0.00500	0.20369
13 RETAIL CUSTOMERS	CUSTRET	1.000000	0.67332	0.11793	0.00006	0.00500	0.20369
14 AVAILABLE-SERVICE DROP	CUSER1	0.000000	-	-	-	-	-
15 AVAILABLE-SERVICE DROP	CUSER2	0.000000	-	-	-	-	-
16 AVAILABLE-METERS	CUSER3	0.000000	-	-	-	-	-
17 AVAILABLE-METERS	CUSER4	0.000000	-	-	-	-	-
18 AVAILABLE-CUSTOMER SERVICES	CUSER5	1.000000	0.80342	0.18849	0.00009	0.00800	-
19 AVAILABLE-CUSTOMER SERVICES	CUSER6	0.000000	-	-	-	-	-
20 CUSTOMER ENERGY SPLIT 907-916	CUSER7	1.000000	0.48636	0.32358	0.07800	0.00526	0.10679
21 AVAILABLE-CUSTOMER BILLING	CUSER8	0.000000	-	-	-	-	-
22 AVAILABLE-CUSTOMER BILLING	CUSER9	1.000000	0.56238	0.34421	0.08346	0.00527	0.00468
23 AVAILABLE-CUSTOMER LTG AND MISC REV	CUSER10	0.000000	-	-	-	-	-
24 AVAILABLE-CUSTOMER LTG AND MISC REV							
25 AVAILABLE-CUSTOMER OTHER							
REVENUE RELATED STRINGS							
------------------------------------							
29 SALES OF ELECTRICITY-BASE	R40B	1.000000	0.41526	0.45732	0.08630	0.00583	0.03529
30 GROSS RECEIPTS FACTOR	RGR	1.000000	0.13333	0.33333	0.26667	0.13333	0.13333
31 CLAIMED RATE OF RETURN	ROR	11.000000	1.00000	4.00000	2.00000	2.00000	2.00000
32 CLAIMED FACTORING	RFACT	3.317629	2.68736	0.57410	0.05616	-	-
33 PROPOSED REVENUES	PREV	1.000000	0.41883	0.47064	0.08851	0.00509	0.01692

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	TOTAL AR RETAIL JURISDICTION (1)	RESIDENTIAL (2)	COMMERCIAL / SMALL INDUSTRIAL (3)	LARGE INDUSTRIAL (4)	MUNICIPAL (5)	LIGHTING (6)
34 FEDERAL INCOME TAX RATE							
35 LOUISIANA APPORTIONMENT FACTOR							
36 LOUISIANA INCOME TAX RATE							
37 ARKANSAS APPORTIONMENT FACTOR							
38 ARKANSAS INCOME TAX RATE							
SCHEDULE G-4 INTERNALLY DEVELOPED							
1 PRODUCTION PLANT	PRODPLT	1.000000	0.40327	0.48140	0.10580	0.00422	0.00531
2 PLANT ACCOUNT 352	PLT352	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020
3 PLANT ACCOUNT 353	PLT353	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020
4 PLANT ACCOUNTS 352 & 353	TRANSUB	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020
5 PLANT ACCOUNTS 354, 355 & 356	TRANOHLN	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020
6 PLANT ACCOUNT 357	TRANUGLN	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020
7 TRANSMISSION PLANT	TRANPLT	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020
8 PROD. & TRANS. PLANT	PTPLT	1.000000	0.39696	0.48287	0.11247	0.00445	0.00325
9 PLANT ACCOUNT 361	PLT361	1.000000	0.42776	0.49892	0.05389	0.00566	0.01377
10 PLANT ACCOUNT 362	PLT362	1.000000	0.42776	0.49892	0.05389	0.00566	0.01377
11 PLANT ACCOUNT 368	PLT368	1.000000	0.42776	0.49892	0.05389	0.00566	0.01377
12 PLANT ACCOUNT 370	PLT370	1.000000	0.66295	0.31867	0.00843	0.00996	-
13 PLANT ACCOUNT 371	PLT371	1.000000	-	-	-	-	1.00000
14 PLANT ACCOUNT 373	PLT373	1.000000	-	-	-	-	1.00000
15 PLANT ACCOUNT 361 & 362	DISTSUB	1.000000	0.42776	0.49892	0.05389	0.00566	0.01377
16 PLANT ACCOUNT 364 & 365	DISTOHLN	1.000000	0.45477	0.48849	0.03609	0.00601	0.01464
17 PLANT ACCOUNT 366 & 367	DISTUGLN	1.000000	0.47093	0.48225	0.02544	0.00623	0.01516
18 DISTRIBUTION PLANT	DISTPLT	1.000000	0.45857	0.45249	0.03596	0.00598	0.04700
19 TRANS. & DISTR. PLANT	TDPLT	1.000000	0.42509	0.46785	0.07672	0.00542	0.02492
20 PROD., TRANS., & DISTR. PLANT	PTDPLT	1.000000	0.41611	0.47343	0.08868	0.00493	0.01685
21 GENERAL PLANT EXCL ADJUSTMENTS	GENPLTX	1.000000	0.36211	0.50146	0.12444	0.00477	0.00722
22 GENERAL PLANT	GENPLT	1.000000	0.36211	0.50146	0.12444	0.00477	0.00722
23 TOTAL ELECTRIC PLANT IN SERVICE	PLANT	1.000000	0.41373	0.47458	0.09000	0.00493	0.01678
24 NET PLANT IN SERVICE	NETPLT	1.000000	0.41588	0.47326	0.08743	0.00503	0.01841
25 RATE BASE	RBX	1.000000	0.41547	0.47277	0.08825	0.00504	0.01847
26 OPERATING EXPENSE ACCT NO. 500	OX500	1.000000	0.38490	0.49035	0.11412	0.00447	0.00616
27 OPERATING EXPENSE ACCT NO. 501	OX501	1.000000	0.30241	0.53054	0.15148	0.00558	0.00998
28 OPERATING EXPENSE ACCT NO. 502	OX502	1.000000	0.40327	0.48140	0.10580	0.00422	0.00531
29 OPERATING EXPENSE ACCT NO. 505	OX505	1.000000	0.40327	0.48140	0.10580	0.00422	0.00531
30 OPERATING EXPENSE ACCT NO. 506	OX506	1.000000	0.40327	0.48140	0.10580	0.00422	0.00531
31 MAINTENANCE EXPENSE ACCT NO. 510	MX510	1.000000	0.31255	0.52561	0.14689	0.00544	0.00951
32 MAINTENANCE EXPENSE ACCT NO. 511	MX511	1.000000	0.40327	0.48140	0.10580	0.00422	0.00531
33 MAINTENANCE EXPENSE ACCT NO. 512	MX512	1.000000	0.30241	0.53054	0.15148	0.00558	0.00998
34 MAINTENANCE EXPENSE ACCT NO. 513	MX513	1.000000	0.30241	0.53054	0.15148	0.00558	0.00998
35 MAINTENANCE EXPENSE ACCT NO. 514	MX514	1.000000	0.40327	0.48140	0.10580	0.00422	0.00531
36 OPERATING EXPENSE ACCT NO. 546	OX546	0.000000	-	-	-	-	-
37 OPERATING EXPENSE ACCT NO. 548	OX548	1.000000	0.40327	0.48140	0.10580	0.00422	0.00531
38 OPERATING EXPENSE ACCT NO. 549	OX549	0.000000	-	-	-	-	-
39 MAINTENANCE EXPENSE ACCT NO. 551	MX551	0.000000	-	-	-	-	-
40 MAINTENANCE EXPENSE ACCT NO. 552	MX552	0.000000	-	-	-	-	-
SCHEDULE G-4 INTERNALLY DEVELOPED (CON'T)							
1 MAINTENANCE EXPENSE ACCT NO. 553	MX553	1.000000	0.40327	0.48140	0.10580	0.00422	0.00531
2 MAINTENANCE EXPENSE ACCT NO. 554	MX554	1.000000	0.40327	0.48140	0.10580	0.00422	0.00531
3 OPERATING EXPENSE ACCT NO. 556	OX556	1.000000	0.40327	0.48140	0.10580	0.00422	0.00531
4 OPERATING EXPENSE ACCT NO. 557	OX557	1.000000	0.40327	0.48140	0.10580	0.00422	0.00531
5 OPERATING EXPENSE ACCT NO. 560	OX560	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020
6 OPERATING EXPENSE ACCT NO. 561	OX561	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020
7 OPERATING EXPENSE ACCT NO. 562	OX562	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	TOTAL AR RETAIL JURISDICTION	RESIDENTIAL	COMMERCIAL / SMALL INDUSTRIAL	LARGE INDUSTRIAL	MUNICIPAL	LIGHTING
		(1)	(2)	(3)	(4)	(5)	(6)
8 OPERATING EXPENSE ACCT NO. 563	OX563	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020
9 OPERATING EXPENSE ACCT NO. 564	OX564	0.000000	-	-	-	-	-
10 OPERATING EXPENSE ACCT NO. 565	OX565	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020
11 OPERATING EXPENSE ACCT NO. 566	OX566	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020
12 MAINTENANCE EXPENSE ACCT NO. 568	MX568	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020
13 MAINTENANCE EXPENSE ACCT NO. 569	MX569	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020
14 MAINTENANCE EXPENSE ACCT NO. 570	MX570	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020
15 MAINTENANCE EXPENSE ACCT NO. 571	MX571	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020
16 MAINTENANCE EXPENSE ACCT NO. 572	MX572	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020
17 MAINTENANCE EXPENSE ACCT NO. 573	MX573	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020
18 OPERATING EXPENSE ACCT NO. 580	OX580	1.000000	0.48123	0.42319	0.02933	0.00651	0.05974
19 OPERATING EXPENSE ACCT NO. 581	OX581	1.000000	0.45857	0.45249	0.03596	0.00598	0.04700
20 OPERATING EXPENSE ACCT NO. 582	OX582	1.000000	0.42776	0.49692	0.05389	0.00566	0.01377
21 OPERATING EXPENSE ACCT NO. 583	OX583	1.000000	0.45477	0.48849	0.03609	0.00601	0.01464
22 OPERATING EXPENSE ACCT NO. 584	OX584	1.000000	0.47093	0.48225	0.02544	0.00623	0.01516
23 OPERATING EXPENSE ACCT NO. 585	OX585	1.000000	-	-	-	-	1.00000
24 OPERATING EXPENSE ACCT NO. 586	OX586	1.000000	0.66295	0.31867	0.00843	0.00996	-
25 OPERATING EXPENSE ACCT NO. 587	OX587	1.000000	-	-	-	-	1.00000
26 OPERATING EXPENSE ACCT NO. 588	OX588	1.000000	0.45857	0.45249	0.03596	0.00598	0.04700
27 OPERATING EXPENSE ACCT NO. 589	OX589	1.000000	0.45857	0.45249	0.03596	0.00598	0.04700
28 MAINTENANCE EXPENSE ACCT NO. 590	MX590	1.000000	0.44488	0.45839	0.03315	0.00594	0.05764
29 MAINTENANCE EXPENSE ACCT NO. 591	MX591	1.000000	0.42776	0.49692	0.05389	0.00566	0.01377
30 MAINTENANCE EXPENSE ACCT NO. 592	MX592	1.000000	0.42776	0.49692	0.05389	0.00566	0.01377
31 MAINTENANCE EXPENSE ACCT NO. 593	MX593	1.000000	0.45477	0.48849	0.03609	0.00601	0.01464
32 MAINTENANCE EXPENSE ACCT NO. 594	MX594	1.000000	0.47093	0.48225	0.02544	0.00623	0.01516
33 MAINTENANCE EXPENSE ACCT NO. 595	MX595	1.000000	0.42776	0.49692	0.05389	0.00566	0.01377
34 MAINTENANCE EXPENSE ACCT NO. 596	MX596	1.000000	-	-	-	-	1.00000
35 MAINTENANCE EXPENSE ACCT NO. 597	MX597	1.000000	0.66295	0.31867	0.00843	0.00996	-
36 MAINTENANCE EXPENSE ACCT NO. 598	MX598	1.000000	-	-	-	-	1.00000
37 OPERATING EXPENSE ACCT NO. 901	OX901	1.000000	0.78315	0.14772	0.06227	0.00568	0.00117
38 OPERATING EXPENSE ACCT NO. 902	OX902	1.000000	0.80342	0.18849	0.00009	0.00800	-
39 OPERATING EXPENSE ACCT NO. 903	OX903	1.000000	0.77972	0.14081	0.07282	0.00528	0.00137
40 OPERATING EXPENSE ACCT NO. 904	OX904	1.000000	0.41526	0.45732	0.08630	0.00583	0.03529

SCHEDULE G-4
INTERNALLY DEVELOPED (CON'T)

	ALLOC	TOTAL AR RETAIL JURISDICTION	RESIDENTIAL	COMMERCIAL / SMALL INDUSTRIAL	LARGE INDUSTRIAL	MUNICIPAL	LIGHTING
1 OPERATING EXPENSE ACCT NO. 905	OX905	1.000000	0.78315	0.14772	0.06227	0.00568	0.00117
2 OPERATING EXPENSE ACCT NO. 907	OX907	1.000000	0.48636	0.32358	0.07800	0.00526	0.10679
3 OPERATING EXPENSE ACCT NO. 908	OX908	1.000000	0.48636	0.32358	0.07800	0.00526	0.10679
4 OPERATING EXPENSE ACCT NO. 909	OX909	1.000000	0.48636	0.32358	0.07800	0.00526	0.10679
5 OPERATING EXPENSE ACCT NO. 910	OX910	1.000000	0.48636	0.32358	0.07800	0.00526	0.10679
6 OPERATING EXPENSE ACCT NO. 911	OX911	1.000000	0.48636	0.32358	0.07800	0.00526	0.10679
7 OPERATING EXPENSE ACCT NO. 912	OX912	1.000000	0.48636	0.32358	0.07800	0.00526	0.10679
8 OPERATING EXPENSE ACCT NO. 913	OX913	1.000000	0.48636	0.32358	0.07800	0.00526	0.10679
9 OPERATING EXPENSE ACCT NO. 916	OX916	0.000000	-	-	-	-	-
10 OPERATING EXPENSE ACCT NO. 920	OX920	1.000000	0.44836	0.43078	0.09038	0.00528	0.02520
11 OPERATING EXPENSE ACCT NO. 921	OX921	1.000000	0.44836	0.43078	0.09038	0.00528	0.02520
12 OPERATING EXPENSE ACCT NO. 922	OX922	1.000000	0.44836	0.43078	0.09038	0.00528	0.02520
13 OPERATING EXPENSE ACCT NO. 923	OX923	1.000000	0.44836	0.43078	0.09038	0.00528	0.02520
14 1/8 O&M LESS FUEL & PURCHASED PWR	OMX	1.000000	0.42285	0.45679	0.09981	0.00514	0.01540
15 DEPRECIATION EXPENSE	DEPREXP	1.000000	0.41676	0.47328	0.08721	0.00494	0.01780
16 AD VALOREM TAXES	PROPTAX	1.000000	0.41373	0.47458	0.09000	0.00493	0.01678
17 LABOR ACCOUNTS 501 THRU 507	LAB501_507	1.000000	0.38490	0.49035	0.11412	0.00447	0.00616
18 LABOR ACCOUNTS 511 THRU 514	LAB511_514	1.000000	0.31255	0.52561	0.14689	0.00544	0.00951
19 LABOR ACCOUNTS 547 THRU 550	LAB547_550	1.000000	0.40327	0.48140	0.10580	0.00422	0.00531
20 LABOR ACCOUNTS 552 THRU 554	LAB552_554	1.000000	0.40327	0.48140	0.10580	0.00422	0.00531
21 LABOR ACCOUNTS 561 THRU 567	LAB561_567	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020
22 LABOR ACCOUNTS 569 THRU 573	LAB569_573	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020
23 LABOR ACCOUNTS 581 THRU 589	LAB581_589	1.000000	0.48123	0.42319	0.02933	0.00651	0.05974

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	TOTAL AR RETAIL JURISDICTION (1)	RESIDENTIAL (2)	COMMERCIAL / SMALL INDUSTRIAL (3)	LARGE INDUSTRIAL (4)	MUNICIPAL (5)	LIGHTING (6)
24 LABOR ACCOUNTS 591 THRU 598	LAB591_598	1.000000	0.44486	0.45839	0.03315	0.00594	0.05764
25 LABOR ACCOUNTS 902 THRU 905	LAB902_905	1.000000	0.78315	0.14772	0.06227	0.00568	0.00117
26 LABOR ACCOUNTS 908 THRU 910	LAB908_910	1.000000	0.48636	0.32358	0.07800	0.00526	0.10679
27 LABOR ACCOUNTS 912 THRU 916	LAB912_916	1.000000	0.48636	0.32358	0.07800	0.00526	0.10679
28 PAYROLL EXCLUDING A&G	LABORX	1.000000	0.44970	0.43018	0.09006	0.00531	0.02475
29 RETAIL PAYROLL EXCLUDING A&G	LABORXR	1.000000	0.44970	0.43018	0.09006	0.00531	0.02475
30 TOTAL PAYROLL	LABORT	1.000000	0.44836	0.43078	0.09038	0.00528	0.02520
31 ACCT 903 EXCL BILLING	OX903X	0.000000	-	-	-	-	-
32 ACCT 903 BILLING	OX903B	1.000000	0.77972	0.14081	0.07282	0.00528	0.00137
33 PRODUCTION LABOR	LABPROD	1.000000	0.36211	0.50146	0.12444	0.00477	0.00722
34 TRANSMISSION LABOR	LABTRAN	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020
35 DISTR LABOR EXCL METERING	LABDIST	1.000000	0.44228	0.45084	0.03367	0.00582	0.06738
36 CUST SERVICE LABOR EXCL METER & BILLING	LABCUSSV	1.000000	0.67721	0.20506	0.07419	0.00529	0.03825
37 METERING LABOR	LABMETER	1.000000	0.71110	0.27404	0.00557	0.00929	-
38 BILLING LABOR	LABBILL	0.000000	-	-	-	-	-

SCHEDULE G-4
INTERNALLY DEVELOPED (CON'T)

1 SALES REVENUE	REVSALES	1.000000	0.41526	0.45732	0.08630	0.00583	0.03529
2 0.5*PRODPLT + 0.95*TDPLT	PTDPLTW	1.000000	0.41922	0.47149	0.08454	0.00510	0.01965
3 REV DEF @ CLAIMED * FACTORING	FACTC	0.000000	-	-	-	-	-
4 REV DEF @ PROPOSED * FACTORING	FACTP	0.000000	-	-	-	-	-
5 COS @ CLAIMED * AR REV REL TAX	REVFACC1	1.000000	0.13333	0.33333	0.26667	0.13333	0.13333
6 COS @ CLAIMED * LA REV RELA TAX	REVFACC2	0.000000	-	-	-	-	-
7 COS @ CLAIMED * TX REV REL TAX	REVFACC3	0.000000	-	-	-	-	-
8 PROPOSED REV * AR REV REL TX	REVFACP1	1.000000	0.13333	0.33333	0.26667	0.13333	0.13333
9 PROPOSED REV * LA REV REL TAX	REVFACP2	0.000000	-	-	-	-	-
10 PROPOSED REV * TX REV REL TAX	REVFACP3	0.000000	-	-	-	-	-
11 FUEL - RETAIL	FUELR	1.000000	0.30241	0.53054	0.15148	0.00558	0.00998
12 FUEL - WHOLESALE	FUELW	0.000000	-	-	-	-	-
13 SALES REVENUE - RETAIL	REVSALESR	1.000000	0.41526	0.45732	0.08630	0.00583	0.03529
14 SALES REVENUE - WHOLESALE	REVSALESW	0.000000	-	-	-	-	-
15 SALES REVENUE - ARKANSAS	REVSALEAR	1.000000	0.41526	0.45732	0.08630	0.00583	0.03529
16 SALES REVENUE - LOUISIANA	REVSALELA	0.000000	-	-	-	-	-
17 SALES REVENUE - TEXAS	REVSALETX	0.000000	-	-	-	-	-
18 PRODUCTION PLANT - TEXAS	PRODPLTTX	0.000000	-	-	-	-	-
19 DISTRIBUTION PLANT - LOUISIANA	DISTPLTLA	0.000000	-	-	-	-	-
20 RETAIL REVENUE LA	RREVLA	0.000000	-	-	-	-	-
21 TAXABLE INCOME LA	TAXINCLA	0.000000	-	-	-	-	-
22 TAXABLE INCOME AR	TAXINCAR	1.000000	0.42028	0.50909	0.12708	0.00226	(0.05871)
23 PLANT LA	PLANTLA	0.000000	-	-	-	-	-
24 PLANT AR	PLANTAR	1.000000	0.41373	0.47458	0.09000	0.00493	0.01678
25 DEMAND PROD WHOLESALE	DPRODWH	0.000000	-	-	-	-	-
26 DEMAND PROD ARKANSAS	DPRODAR	1.000000	0.40327	0.48140	0.10580	0.00422	0.00531
27 DEMAND PROD LOUISIANA	DPRODLA	0.000000	-	-	-	-	-
28 DEMAND PROD TEXAS	DPRODTX	0.000000	-	-	-	-	-
29 DEMAND TRAN WHOLESALE	DTRANWH	0.000000	-	-	-	-	-
30 DEMAND TRAN ARKANSAS	DTRANAR	1.000000	0.38761	0.48504	0.12235	0.00480	0.00020
31 DEMAND TRAN LOUISIANA	DTRANLA	0.000000	-	-	-	-	-
32 DEMAND TRAN TEXAS	DTRANTX	0.000000	-	-	-	-	-
33 DEMAND DIST WHOLESALE	DDISTWH	0.000000	-	-	-	-	-
34 DEMAND DIST ARKANSAS	DDISTAR	1.000000	0.45857	0.45249	0.03596	0.00598	0.04700
35 DEMAND DIST LOUISIANA	DDISTLA	0.000000	-	-	-	-	-
36 DEMAND DIST TEXAS	DDISTTX	0.000000	-	-	-	-	-
37 DEMAND GENERAL WHOLESALE	DGENLWH	0.000000	-	-	-	-	-
38 DEMAND GENERAL ARKANSAS	DGENLAR	1.000000	0.36211	0.50146	0.12444	0.00477	0.00722
39 DEMAND GENERAL LOUISIANA	DGENLLA	0.000000	-	-	-	-	-

SOUTHWESTERN ELECTRIC POWER COMPANY
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CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	TOTAL AR RETAIL JURISDICTION (1)	RESIDENTIAL (2)	COMMERCIAL / SMALL INDUSTRIAL (3)	LARGE INDUSTRIAL (4)	MUNICIPAL (5)	LIGHTING (6)
40 DEMAND GENERAL TEXAS	DGENLTX	0.000000	-	-	-	-	-
SCHEDULE G-4 INTERNALLY DEVELOPED (CON'T)							
1 PRODUCTION PLANT - TEXAS RETAIL	PRODPLTT	0.000000	-	-	-	-	-
2 LABOR 902 & 903	LAB902_903	1.000000	0.78315	0.14772	0.06227	0.00568	0.00117
3 SALES REVENUE - AR RETAIL	RVSALEARR	1.000000	0.41526	0.45732	0.08630	0.00583	0.03529
4 SALES REVENUE - LA RETAIL	RVSALELAR	0.000000	-	-	-	-	-
5 SALES REVENUE - TX RETAIL	RVSALETXR	0.000000	-	-	-	-	-
6 DIST PLANT BEFORE CONTRA ADJ	DISTPLTX	1.000000	0.45857	0.45249	0.03596	0.00598	0.04700
7 STATE INCOME TAX	SIT	1.000000	0.41998	0.50750	0.12537	0.00238	(0.05524)
8 RETAIL PRODUCTION PLANT	PRODPLTR	1.000000	0.40327	0.48140	0.10580	0.00422	0.00531
9 TOTAL kWh AT GEN - ARKANSAS	KWHAR	1.000000	0.30241	0.53054	0.15148	0.00558	0.00998
10 TOTAL kWh AT GEN- LOUISIANA	KWHLA	0.000000	-	-	-	-	-
11 TOTAL kWh AT GEN- TEXAS	KWHTX	0.000000	-	-	-	-	-
12 INTANGIBLE PLANT	INTPLT	1.000000	0.40137	0.47662	0.08470	0.00523	0.03208
13 DEMPROD RETAIL	DEMRTAIL	1.000000	0.40327	0.48140	0.10580	0.00422	0.00531
14 FIT TEMPORARY DIFFERENCES	FITTEMP	1.000000	0.40506	0.47774	0.09654	0.00496	0.01570
15 Total Depr Expense	DEPEXP	1.000000	0.41676	0.47328	0.08721	0.00494	0.01780
16 AVAILABLE	AVAIL	0.000000	-	-	-	-	-
17 Composite Tax Rate (FIT and AR State)	COMPTR	11.000000	1.00000	4.00000	2.00000	2.00000	2.00000
18 Combined Tax Gross Up (FIT and AR State)	TAX GU	11.000000	1.00000	4.00000	2.00000	2.00000	2.00000
19 CLAIMED FACTORING	RFACT	3.317629	2.68736	0.57410	0.05616	-	-
20 Gross Revenue Conversion Factor	REVCONV	10.975419	1.00545	3.98901	1.99377	1.99359	1.99359
21 AVAILABLE	AVAIL	0.000000	-	-	-	-	-
22 AVAILABLE	AVAIL	0.000000	-	-	-	-	-

Supporting Schedules
(a) G-5.1 or G-5.2
(b) H-1
WP's G-2
WP's G-2 and G-3
G Class WP

Recap Schedules
(A) G-2, G-3

SOUTHWESTERN ELECTRIC POWER COMPANY
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CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	RESIDENTIAL BASIC (7)	RESIDENTIAL WITH WATER HEAT (8)	RESIDENTIAL WITH SPACE HEAT (9)	TOTAL RESIDENTIAL (10)	COMMERCIAL / SMALL INDUSTRIAL GENERAL UNMETERED (11)	LIGHT & POWER PRI (12)	LIGHT & POWER SEC (13)	PRIMARY SUB (14)	GENERAL SERVICE (15)	C-1 RIDER (16)
SCHEDULE G-4											
ALLOCATION FACTOR TABLE											
CAPACITY RELATED		4CP A&E Prod/12CP Tr					0.13206				
------------------------------------											
1 PRODUCTION ALLOCATOR	DEMPROD	0.34691		0.056362	0.40327		0.10029	0.26546		0.11238	
2											
3 TRANSMISSION FUNCTION	DEMTRANS	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
4 D. A. ACCT 360 - LAND (MDD)	DEM360DA	350,139		70,916	421,055		101,730	261,420		121,111	
5 D. A. ACCT 361 - STRUCTURES & IMPROVE	DEM361DA	350,139		70,916	421,055		101,730	261,420		121,111	
6 D. A. ACCT 362 - STATION EQUIPMENT	DEM362DA	350,139		70,916	421,055		101,730	261,420		121,111	
7 D. A. ACCT 364 - PRI POLES, TOWERS & FIX	DEM364DAP	350,139		70,916	421,055		101,730	261,420		121,111	
8 D. A. ACCT 364 - SEC-POLES, TOWERS & FIX	DEM364DAS	350,139		70,916	421,055		-	261,420		121,111	
9 D. A. ACCT 365 - PRI - OVRHD COND & DEVICES	DEM365DAP	350,139		70,916	421,055		101,730	261,420		121,111	
10 D. A. ACCT 365 - SEC - OVRHD COND & DEVICES	DEM365DAS	350,139		70,916	421,055		-	261,420		121,111	
11 D. A. ACCT 366 - PRI - UNDERGROUND CONDUIT	DEM366DAP	350,139		70,916	421,055		101,730	261,420		121,111	
12 D. A. ACCT 366 - SEC- UNDERGROUND CONDUIT	DEM366DAS	350,139		70,916	421,055		-	261,420		121,111	
13 D. A. ACCT 367 - PRI - UNDGRD COND & DEVICE	DEM367DAP	350,139		70,916	421,055		101,730	261,420		121,111	
14 D. A. ACCT 367 - SEC - UNDGRD COND & DEVICE	DEM367DAS	350,139		70,916	421,055		-	261,420		121,111	
15 D. A. ACCT 368 - LINE TRANSORMERS	DEM368DA	350,139		70,916	421,055		101,730	261,420		121,111	
16 ANNUAL BILLING DEMAND	DEM99	65,076		18,676	83,753		1,178,414	3,082,841		1,052,079	
17 SPP DEMAND	SPPDEMAND	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
18 AVAILABLE-SUBSTATIONS	USERSUB	-		-	-		-	-		-	
19 AVAILABLE-DIR ASSIGN SUBS	USERDASUB	-		-	-		-	-		-	
20 AVAILABLE-PRI OVHD	USEROVHD	-		-	-		-	-		-	
21 AVAILABLE-SECONDARY	USERSEC	-		-	-		-	-		-	
22											
23											
24											
25 COMMODITY RELATED											
26 ------------------------------------											
27 FUEL ALLOCATION	FUEL	29,499,090		6,523,213	36,022,303		16,890,968	34,495,603		11,883,621	
28 KWH SALES AT GENERATOR	ENERGY	1,026,042,322		223,116,232	1,249,158,554		573,557,592	1,182,105,893		411,370,112	
29 SALES OF ELECTRICITY - PRESENT FUEL	REVFUEL	-		-	-		-	-		-	
30 KWH SALES AT METER	ENERGY99	951,051,881		206,809,318	1,157,861,199		546,506,764	1,095,709,221		381,304,270	
31 MINE CLOSING	MINECLOSE	-		-	-		-	-		-	
32 MINE CLOSING NFIRM RETAIL	MINECLOSEN	-		-	-		-	-		-	
33 NON FIRM FUEL PRESENT FUEL	NFREVFUEL	-		-	-		-	-		-	
34 FUEL ADJUSTMENT	FUELADJ	-		-	-		-	-		-	
35 NON FIRM PROPOSED FUEL RETAIL	NFPROPFUEL	-		-	-		-	-		-	
36 PROPOSED FUEL REVENUE	PROPFUEL	-		-	-		-	-		-	
SCHEDULE G-4											
CUSTOMER RELATED											
------------------------------------											
1 ANNUAL AVERAGE CUSTOMERS	CUST99	87,592		13,913	101,505		49	1,616		16,111	
2 YEAR END NUMBER OF CUSTOMERS	CUST	87,592		13,913	101,505		49	1,616		16,111	
3 WEIGHTED SERVICES	CUST369	87,557		13,947	101,504		138	3,104		18,849	
4 WEIGHTED METERS	CUST370	87,557		13,912	101,469		3,471	13,172		32,044	
5 ASSIGNED CUSTOMER INSTALLATIONS	CUST371L	-		-	-		-	-		-	
6 LIGHTING ASSIGNMENTS	CUST373	-		-	-		-	-		-	
7 WEIGHTED METERS	CUST902	87,557		13,947	101,504		66	2,166		21,578	
8 CUSTOMER ACCOUNTING	CUST903	87,557		13,948	101,505		49	1,616		16,111	
9 CUSTOMER INFO EXP ALLOC	CUSTINFO	87,592		13,913	101,505		49	1,616		16,111	
10 CUSTOMER SERVICE EXP ALLOC	CUSTSRVC	87,592		13,913	101,505		49	1,616		16,111	
11 ACTIVE CUSTOMER DEPOSITS	CUSTDEPA	-		-	-		-	-		-	
12 CUSTOMERS IN AR & LA	CUSTARLA	87,592		13,913	101,505		49	1,616		16,111	
13 RETAIL CUSTOMERS	CUSTRET	87,592		13,913	101,505		49	1,616		16,111	
14 AVAILABLE-SERVICE DROP	CUSER1	-		-	-		-	-		-	
15 AVAILABLE-SERVICE DROP	CUSER2	-		-	-		-	-		-	
16 AVAILABLE-METERS	CUSER3	-		-	-		-	-		-	

SOUTHWESTERN ELECTRIC POWER COMPANY
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CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	RESIDENTIAL BASIC (7)	RESIDENTIAL WITH WATER HEAT (8)	RESIDENTIAL WITH SPACE HEAT (9)	TOTAL RESIDENTIAL (10)	COMMERCIAL / SMALL INDUSTRIAL GENERAL UNMETERED (11)	LIGHT & POWER PRI (12)	LIGHT & POWER SEC (13)	PRIMARY SUB (14)	GENERAL SERVICE (15)	C-1 RIDER (16)
17 AVAILABLE-METERS	CUSER4	-		-	-		-	-		-	
18 AVAILABLE-CUSTOMER SERVICES	CUSER5	87,557		13,947	101,504		66	2,166		21,578	
19 AVAILABLE-CUSTOMER SERVICES	CUSER6	-		-	-		-	-		-	
20 CUSTOMER ENERGY SPLIT 907-916	CUSER7	0.41348		0.07288	0.4864		0.07082	0.14703		0.10273	
21 AVAILABLE-CUSTOMER BILLING	CUSER8	-		-	-		-	-		-	
22 AVAILABLE-CUSTOMER BILLING	CUSER9	0		0	1		0	0		0	
23 AVAILABLE-CUSTOMER LTG AND MISC REV	CUSER10	-		-	-		-	-		-	
24 AVAILABLE CUSTOMER LTG AND MISC REV	CUSER11	-		-	-		-	-		-	
25 AVAILABLE-CUSTOMER OTHER	CUSER12	-		-	-		-	-		-	
26											
27 REVENUE RELATED STRINGS											
28 --											
29 SALES OF ELECTRICITY-BASE	R40B	45,329,686		8,315,373	53,645,062		12,101,967	30,742,086		15,799,494	
30 GROSS RECEIPTS FACTOR	RGR	0.0000		0.0000	0.0000		0.0000	0.0000		0.0000	
31 CLAIMED RATE OF RETURN	ROR	0.0521		0.0521	0.0521		0.0521	0.0521		0.0521	
32 CLAIMED FACTORING	RFACT	0.008613	0.008613	0.008613	0.008613	0.000460	0.000460	0.000460	0.000460	0.000460	0.000460
33 PROPOSED REVENUES	PREV	72,096,294		13,225,247	85,321,541		19,889,732	51,719,681		23,295,012	
34 FEDERAL INCOME TAX RATE		0.21000	0.21000	0.21000	0.21000	0.21000	0.21000	0.21000	0.21000	0.21000	0.21000
35 LOUISIANA APPORTIONMENT FACTOR		0.24386	0.24386	0.24386	0.24386	0.24386	0.24386	0.24386	0.24386	0.24386	0.24386
36 LOUISIANA INCOME TAX RATE		0.06500	0.06500	0.06500	0.06500	0.06500	0.06500	0.06500	0.06500	0.06500	0.06500
37 ARKANSAS APPORTIONMENT FACTOR		0.24386	0.24386	0.24386	0.24386	0.24386	0.24386	0.24386	0.24386	0.24386	0.24386
38 ARKANSAS INCOME TAX RATE		0.06500	0.06500	0.06500	0.06500	0.06500	0.06500	0.06500	0.06500	0.06500	0.06500
SCHEDULE G-4											
INTERNALLY DEVELOPED											
--											
1 PRODUCTION PLANT	PRODPLT	211,351,821		34,338,441	245,690,263		61,100,273	161,732,219		68,469,129	
2 PLANT ACCOUNT 352	PLT352	1,082,814		224,507	1,307,322		389,748	890,123		343,015	
3 PLANT ACCOUNT 353	PLT353	45,024,860		9,335,320	54,360,180		16,206,247	37,012,503		14,263,018	
4 PLANT ACCOUNTS 352 & 353	TRANSUB	46,107,674		9,559,828	55,667,502		16,595,995	37,902,626		14,606,033	
5 PLANT ACCOUNTS 354, 355 & 356	TRANOHLN	78,629,336		16,302,772	94,932,107		28,301,841	64,636,925		24,908,276	
6 PLANT ACCOUNT 357	TRANUGLN	152,238		31,565	183,803		54,797	125,147		48,226	
7 TRANSMISSION PLANT	TRANPLT	132,081,695		27,385,425	159,467,120		47,541,482	108,577,219		41,840,966	
8 PROD. & TRANS. PLANT	PTPLT	343,433,517		61,723,866	405,157,383		108,641,755	270,309,439		110,310,095	
9 PLANT ACCOUNT 361	PLT361	896,054		181,483	1,077,537		260,341	669,010		309,939	
10 PLANT ACCOUNT 362	PLT362	28,796,431		5,832,303	34,628,734		8,366,555	21,499,935		9,960,477	
11 PLANT ACCOUNT 368	PLT368	21,217,918		4,297,384	25,515,303		6,164,683	15,841,681		7,339,124	
12 PLANT ACCOUNT 370	PLT370	10,608,733		1,685,630	12,294,363		420,559	1,595,969		3,882,571	
13 PLANT ACCOUNT 371	PLT371	-		-	-		-	-		-	
14 PLANT ACCOUNT 373	PLT373	-		-	-		-	-		-	
15 PLANT ACCOUNT 361 & 362	DISTSUB	29,692,485		6,013,786	35,706,271		8,626,895	22,168,945		10,270,415	
16 PLANT ACCOUNT 364 & 365	DISTOHLN	69,986,104		14,174,679	84,160,784		12,806,907	52,252,889		24,207,686	
17 PLANT ACCOUNT 366 & 367	DISTUGLN	29,017,342		5,877,045	34,894,387		3,614,592	21,664,871		10,036,888	
18 DISTRIBUTION PLANT	DISTPLT	176,527,443		34,630,132	211,157,575		31,892,955	114,618,967		59,276,796	
19 TRANS. & DISTR. PLANT	TDPLT	308,609,138		62,015,557	370,624,695		79,434,437	223,196,186		101,117,762	
20 PROD., TRANS., & DISTR. PLANT	PTDPLT	519,960,959		96,353,998	616,314,957		140,534,710	384,928,405		169,586,891	
21 GENERAL PLANT EXCL ADJUSTMENTS	GENPLTX	18,747,990		3,386,681	22,134,671		7,092,315	16,743,643		6,550,492	
22 GENERAL PLANT	GENPLT	18,747,990		3,386,681	22,134,671		7,092,315	16,743,643		6,550,492	
23 TOTAL ELECTRIC PLANT IN SERVICE	PLANT	549,060,190		101,746,183	650,806,372		150,512,245	409,792,553		179,657,723	
24 NET PLANT IN SERVICE	NETPLT	351,771,725		66,353,039	418,124,763		95,340,723	261,018,401		115,129,419	
25 RATE BASE	RBX	412,897,169		77,831,509	490,728,678		112,293,614	305,907,794		135,070,534	
26 OPERATING EXPENSE ACCT NO. 500	OX500	1,133,536		192,736	1,326,272		369,766	927,713		379,215	
27 OPERATING EXPENSE ACCT NO. 501	OX501	847,896		184,378	1,032,273		473,974	976,863		339,946	
28 OPERATING EXPENSE ACCT NO. 502	OX502	1,051,269		170,800	1,222,070		303,914	804,460		340,567	
29 OPERATING EXPENSE ACCT NO. 505	OX505	411,022		66,779	477,801		118,823	314,525		133,154	
30 OPERATING EXPENSE ACCT NO. 506	OX506	1,398,919		227,283	1,626,202		404,417	1,070,491		453,191	
31 MAINTENANCE EXPENSE ACCT NO. 510	MX510	242,093		50,847	292,940		126,510	266,273		94,547	
32 MAINTENANCE EXPENSE ACCT NO. 511	MX511	191,389		31,095	222,484		55,329	146,456		62,002	
33 MAINTENANCE EXPENSE ACCT NO. 512	MX512	2,001,793		435,296	2,437,090		1,119,002	2,306,271		802,577	
34 MAINTENANCE EXPENSE ACCT NO. 513	MX513	244,002		53,059	297,061		136,397	281,115		97,827	

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

			RESIDENTIAL				COMMERCIAL / SMALL INDUSTRIAL					
		ALLOC	BASIC	WITH WATER HEAT	WITH SPACE HEAT	TOTAL RESIDENTIAL	GENERAL UNMETERED	LIGHT & POWER PRI	LIGHT & POWER SEC	PRIMARY SUB	GENERAL SERVICE	C-1 RIDER
			(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
35	MAINTENANCE EXPENSE ACCT NO. 514	MX514	276,938		44,994	321,933		80,061	211,921		89,716	
36	OPERATING EXPENSE ACCT NO. 546	OX546	-		-	-		-	-		-	
37	OPERATING EXPENSE ACCT NO. 548	OX548	42,873		6,966	49,839		12,394	32,808		13,889	
38	OPERATING EXPENSE ACCT NO. 549	OX549	-		-	-		-	-		-	
39	MAINTENANCE EXPENSE ACCT NO. 551	MX551	-		-	-		-	-		-	
40	MAINTENANCE EXPENSE ACCT NO. 552	MX552	-		-	-		-	-		-	
	SCHEDULE G-4 INTERNALLY DEVELOPED (CON'T)											
1	MAINTENANCE EXPENSE ACCT NO. 553	MX553	42,754		6,946	49,701		12,360	32,717		13,851	
2	MAINTENANCE EXPENSE ACCT NO. 554	MX554	1,143		186	1,329		331	875		370	
3	OPERATING EXPENSE ACCT NO. 556	OX556	129,655		21,065	150,720		37,482	99,216		42,003	
4	OPERATING EXPENSE ACCT NO. 557	OX557	249,134		40,477	289,611		72,023	190,644		80,709	
5	OPERATING EXPENSE ACCT NO. 560	OX560	487,325		101,040	588,365		175,408	400,603		154,375	
6	OPERATING EXPENSE ACCT NO. 561	OX561	940,357		194,971	1,135,328		338,472	773,017		297,887	
7	OPERATING EXPENSE ACCT NO. 562	OX562	35,234		7,305	42,539		12,682	28,964		11,162	
8	OPERATING EXPENSE ACCT NO. 563	OX563	27,807		5,765	33,572		10,009	22,858		8,809	
9	OPERATING EXPENSE ACCT NO. 564	OX564	-		-	-		-	-		-	
10	OPERATING EXPENSE ACCT NO. 565	OX565	6,930,631		1,436,976	8,367,607		2,494,611	5,697,297		2,195,492	
11	OPERATING EXPENSE ACCT NO. 566	OX566	128,290		26,599	154,890		46,177	105,461		40,640	
12	MAINTENANCE EXPENSE ACCT NO. 568	MX568	2,697		559	3,256		971	2,217		854	
13	MAINTENANCE EXPENSE ACCT NO. 569	MX569	37,581		7,792	45,373		13,527	30,893		11,905	
14	MAINTENANCE EXPENSE ACCT NO. 570	MX570	230,763		47,846	278,609		83,061	189,698		73,101	
15	MAINTENANCE EXPENSE ACCT NO. 571	MX571	677,085		140,385	817,470		243,710	556,595		214,488	
16	MAINTENANCE EXPENSE ACCT NO. 572	MX572	62	-	13	75		22	51	-	20	
17	MAINTENANCE EXPENSE ACCT NO. 573	MX573	2,518	-	522	3,040		906	2,070	-	798	-
18	OPERATING EXPENSE ACCT NO. 580	OX580	195,392		36,796	232,188		27,763	106,775		67,415	
19	OPERATING EXPENSE ACCT NO. 581	OX581	2,404		472	2,875		434	1,561		807	
20	OPERATING EXPENSE ACCT NO. 582	OX582	36,821		7,457	44,278		10,698	27,491		12,736	
21	OPERATING EXPENSE ACCT NO. 583	OX583	227,947		46,167	274,115		41,713	170,190		78,845	
22	OPERATING EXPENSE ACCT NO. 584	OX584	199,128		40,331	239,458		24,805	148,673		68,877	
23	OPERATING EXPENSE ACCT NO. 585	OX585	-		-	-		-	-		-	
24	OPERATING EXPENSE ACCT NO. 586	OX586	399,512		63,479	462,990		15,838	60,102		146,213	
25	OPERATING EXPENSE ACCT NO. 587	OX587	-		-	-		-	-		-	
26	OPERATING EXPENSE ACCT NO. 588	OX588	1,462,347		286,875	1,749,222		264,200	949,500		491,047	
27	OPERATING EXPENSE ACCT NO. 589	OX589	67,992		13,338	81,330		12,284	44,147		22,831	
28	MAINTENANCE EXPENSE ACCT NO. 590	MX590	27,027		5,384	32,411		4,655	18,944		9,390	
29	MAINTENANCE EXPENSE ACCT NO. 591	MX591	2,386		483	2,870		693	1,782		825	
30	MAINTENANCE EXPENSE ACCT NO. 592	MX592	58,739		11,897	70,636		17,066	43,856		20,317	
31	MAINTENANCE EXPENSE ACCT NO. 593	MX593	1,817,706		368,150	2,185,856		332,626	1,357,132		628,731	
32	MAINTENANCE EXPENSE ACCT NO. 594	MX594	94,903		19,221	114,124		11,822	70,856		32,826	
33	MAINTENANCE EXPENSE ACCT NO. 595	MX595	7,009		1,420	8,429		2,036	5,233		2,424	
34	MAINTENANCE EXPENSE ACCT NO. 596	MX596	-		-	-		-	-		-	
35	MAINTENANCE EXPENSE ACCT NO. 597	MX597	54,964		8,733	63,697		2,179	8,269		20,116	
36	MAINTENANCE EXPENSE ACCT NO. 598	MX598	-		-	-		-	-		-	
37	OPERATING EXPENSE ACCT NO. 901	OX901	111,361		16,223	127,583		60	1,983		19,760	
38	OPERATING EXPENSE ACCT NO. 902	OX902	333,202		53,076	386,278		251	8,243		82,116	
39	OPERATING EXPENSE ACCT NO. 903	OX903	2,772,702		397,417	3,170,119		1,398	46,054		459,041	
40	OPERATING EXPENSE ACCT NO. 904	OX904	122,411		22,455	144,866		32,681	83,017		42,666	
	SCHEDULE G-4 INTERNALLY DEVELOPED (CON'T)											
1	OPERATING EXPENSE ACCT NO. 905	OX905	17,297		2,520	19,817		9	308		3,069	
2	OPERATING EXPENSE ACCT NO. 907	OX907	90,489		15,950	106,439		15,499	32,177		22,483	
3	OPERATING EXPENSE ACCT NO. 908	OX908	313,740		55,302	369,042		53,739	111,564		77,953	
4	OPERATING EXPENSE ACCT NO. 909	OX909	1,301		229	1,530		223	463		323	
5	OPERATING EXPENSE ACCT NO. 910	OX910	769		136	905		132	273		191	
6	OPERATING EXPENSE ACCT NO. 911	OX911	29		5	34		5	10		7	

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross refereneces to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	RESIDENTIAL				COMMERCIAL / SMALL INDUSTRIAL					
		BASIC	WITH WATER HEAT	WITH SPACE HEAT	TOTAL RESIDENTIAL	GENERAL UNMETERED	LIGHT & POWER PRI	LIGHT & POWER SEC	PRIMARY SUB	GENERAL SERVICE	C-1 RIDER
		(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
7 OPERATING EXPENSE ACCT NO. 912	OX912	14,968		2,638	17,607		2,564	5,323		3,719	
8 OPERATING EXPENSE ACCT NO. 913	OX913	(2,017)		(355)	(2,372)		(345)	(717)		(501)	
9 OPERATING EXPENSE ACCT NO. 916	OX916	-		-	-		-	-		-	
10 OPERATING EXPENSE ACCT NO. 920	OX920	2,636,607		469,153	3,105,760		590,618	1,558,003		796,647	
11 OPERATING EXPENSE ACCT NO. 921	OX921	191,968		34,159	226,127		43,002	113,437		58,003	
12 OPERATING EXPENSE ACCT NO. 922	OX922	(283,057)		(50,367)	(333,424)		(63,407)	(167,262)		(85,525)	
13 OPERATING EXPENSE ACCT NO. 923	OX923	1,355,304		241,160	1,596,465		303,597	800,866		409,503	
14 1/8 O&M LESS FUEL & PURCHASED PWR	OMX	4,054,775		760,407	4,815,182		1,096,149	2,780,450		1,267,220	
15 DEPRECIATION EXPENSE	DEPREXP	14,913,773		2,745,318	17,659,091		3,983,048	11,013,438		4,880,197	
16 AD VALOREM TAXES	PROPTAX	4,316,464		799,883	5,116,346		1,183,259	3,221,604		1,412,388	
17 LABOR ACCOUNTS 501 THRU 507	LAB501_507	1,185,430		201,560	1,386,990		306,694	970,185		396,576	
18 LABOR ACCOUNTS 511 THRU 514	LAB511_514	700,944		147,220	848,164		366,290	770,955		273,746	
19 LABOR ACCOUNTS 547 THRU 550	LAB547_550	22,224		3,611	25,834		6,425	17,006		7,200	
20 LABOR ACCOUNTS 552 THRU 554	LAB552_554	12,394		2,014	14,408		3,583	9,484		4,015	
21 LABOR ACCOUNTS 561 THRU 567	LAB561_567	120,214		24,925	145,139		43,270	98,822		33,082	
22 LABOR ACCOUNTS 569 THRU 573	LAB569_573	191,086		39,619	230,705		68,779	157,081		60,532	
23 LABOR ACCOUNTS 581 THRU 589	LAB581_589	1,304,999		245,754	1,550,753		185,423	713,137		450,254	
24 LABOR ACCOUNTS 591 THRU 598	LAB591_598	592,549		118,030	710,579		102,062	415,325		205,871	
25 LABOR ACCOUNTS 902 THRU 905	LAB902_905	1,560,626		227,348	1,787,974		944	27,706		276,924	
26 LABOR ACCOUNTS 908 THRU 910	LAB908_910	309,208		54,503	363,711		52,963	109,952		76,626	
27 LABOR ACCOUNTS 912 THRU 916	LAB912_916	70		12	82		12	25		17	
28 PAYROLL EXCLUDING A&G	LABORX	7,637,248		1,357,369	8,994,617		1,700,388	4,481,034		2,312,014	
29 RETAIL PAYROLL EXCLUDING A&G	LABORXR	7,637,248		1,357,369	8,994,617		1,700,388	4,481,034		2,312,014	
30 TOTAL PAYROLL	LABORT	9,063,605		1,612,761	10,676,367		2,030,310	5,355,795		2,733,553	
31 ACCT 903 EXCL BILLING	OX903X	0		0	-		0	0		0	
32 ACCT 903 BILLING	OX903B	2,772,702		397,417	3,170,119		1,393	46,054		459,041	
33 PRODUCTION LABOR	LABPROD	2,930,068		520,294	3,459,362		1,108,437	2,616,814		1,023,757	
34 TRANSMISSION LABOR	LABTRAN	571,675		118,529	690,205		205,769	469,943		181,096	
35 DISTR LABOR EXCL METERING	LABDIST	1,660,273		329,994	1,990,267		291,530	1,145,574		566,718	
36 CUST SERVICE LABOR EXCL METER & BILLING	LABCUSSV	1,883,990		285,517	2,169,507		80,117	188,533		351,426	
37 METERING LABOR	LABMETER	591,242		94,034	685,276		14,535	60,169		189,017	
38 BILLING LABOR	LABBILL	0		0	-		0	0		0	

SCHEDULE G-4
INTERNALLY DEVELOPED (CON'T)

	ALLOC	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
1 SALES REVENUE	REVSALES	45,329,638		8,315,373	53,645,062		12,101,967	30,742,086		15,799,494	
2 0.5*PRODPLT + 0.95*TDPLT	PTDPLTW	398,854,592		76,084,000	474,938,591		106,012,652	292,902,486		130,296,438	
3 REV DEF @ CLAIMED * FACTORING	FACTC	0		0	-		0	0		0	
4 REV DEF @ PROPOSED * FACTORING	FACTP	-		-	-		-	-		-	
5 COS @ CLAIMED * AR REV REL TAX	REVFACC1	1.00000		1.00000	2		1.00000	1.00000		1.00000	
6 COS @ CLAIMED * LA REV RELA TAX	REVFACC2	0.00000		0.00000	-		0.00000	0.00000		0.00000	
7 COS @ CLAIMED * TX REV REL TAX	REVFACC3	0.00000		0.00000	-		0.00000	0.00000		0.00000	
8 PROPOSED REV * AR REV REL TX	REVFACP1	1.00000		1.00000	2		1.00000	1.00000		1.00000	
9 PROPOSED REV * LA REV REL TAX	REVFACP2	0.00000		0.00000	-		0.00000	0.00000		0.00000	
10 PROPOSED REV * TX REV REL TAX	REVFACP3	0.00000		0.00000	-		0.00000	0.00000		0.00000	
11 FUEL - RETAIL	FUELR	847,896		184,378	1,032,273		473,974	976,863		339,946	
12 FUEL - WHOLESALE	FUELW	0		0	-		0	0		0	
13 SALES REVENUE - RETAIL	REVSALESR	45,329,688		8,315,373	53,645,062		12,101,967	30,742,036		15,799,494	
14 SALES REVENUE - WHOLESALE	REVSALESW	0		0	-		0	0		0	
15 SALES REVENUE - ARKANSAS	REVSALEAR	45,329,688		8,315,373	53,645,062		12,101,967	30,742,086		15,799,494	
16 SALES REVENUE - LOUISIANA	REVSALELA	0		0	-		0	0		0	
17 SALES REVENUE - TEXAS	REVSALETX	0		0	-		0	0		0	
18 PRODUCTION PLANT - TEXAS	PRODPLTTX	0		0	-		0	0		0	
19 DISTRIBUTION PLANT - LOUISIANA	DISTPLTLA	0		0	-		0	0		0	
20 RETAIL REVENUE LA	RREVLA	0		0	-		0	0		0	
21 TAXABLE INCOME LA	TAXINCLA	0		0	-		0	0		0	
22 TAXABLE INCOME AR	TAXINCAR	(11,251,865)		(2,132,162)	(13,384,027)		(3,297,354)	(9,988,380)		(2,579,698)	

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross refereneces to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		RESIDENTIAL				COMMERCIAL / SMALL INDUSTRIAL					
							LIGHT & POWER				
	ALLOC	BASIC	WITH WATER HEAT	WITH SPACE HEAT	TOTAL RESIDENTIAL	GENERAL UNMETERED	PRI	SEC	PRIMARY SUB	GENERAL SERVICE	C-1 RIDER
		(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
23 PLANT LA	PLANTLA	0		0	-		0	0		0	
24 PLANT AR	PLANTAR	549,060,190		101,746,183	650,806,372		150,512,245	409,792,553		179,657,723	
25 DEMAND PROD WHOLESALE	DPRODWH	0		0	-		0	0		0	
26 DEMAND PROD ARKANSAS	DPRODAR	208,374,587		33,854,729	242,229,315		60,239,577	159,453,957		67,504,630	
27 DEMAND PROD LOUISIANA	DPRODLA	0		0	-		0	0		0	
28 DEMAND PROD TEXAS	DPRODTX	0		0	-		0	0		0	
29 DEMAND TRAN WHOLESALE	DTRANWH	0		0	-		0	0		0	
30 DEMAND TRAN ARKANSAS	DTRANAR	132,024,744		27,373,616	159,398,361		47,520,983	108,530,403		41,822,925	
31 DEMAND TRAN LOUISIANA	DTRANLA	-		-	-		-	-		-	
32 DEMAND TRAN TEXAS	DTRANTX	-		-	-		-	-		-	
33 DEMAND DIST WHOLESALE	DDISTWH	-		-	-		-	-		-	
34 DEMAND DIST ARKANSAS	DDISTAR	176,809,957		34,685,554	211,495,512		31,943,996	114,802,403		59,371,663	
35 DEMAND DIST LOUISIANA	DDISTLA	-		-	-		-	-		-	
36 DEMAND DIST TEXAS	DDISTTX	-		-	-		-	-		-	
37 DEMAND GENERAL WHOLESALE	DGENLWH	-		-	-		-	-		-	
38 DEMAND GENERAL ARKANSAS	DGENLAR	18,747,990		3,386,681	22,134,671		7,092,315	16,743,643		6,550,492	
39 DEMAND GENERAL LOUISIANA	DGENLLA	-		-	-		-	-		-	
40 DEMAND GENERAL TEXAS	DGENLTX	0		0	0		0	0		0	
SCHEDULE G-4											
INTERNALLY DEVELOPED (CON'T)											
1 PRODUCTION PLANT - TEXAS RETAIL	PRODPLTT	0		0	-		0	0		0	
2 LABOR 902 & 903	LAB902_903	1,557,825		226,939	1,784,765		843	27,736		276,427	
3 SALES REVENUE - AR RETAIL	RVSALEARR	45,329,688		8,315,373	53,645,062		12,101,967	30,742,086		15,799,494	
4 SALES REVENUE - LA RETAIL	RVSALELAR	0		0	-		0	0		0	
5 SALES REVENUE - TX RETAIL	RVSALETXR	0		0	-		0	0		0	
6 DIST PLANT BEFORE CONTRA ADJ	DISTPLTX	176,809,957		34,685,554	211,495,512		31,943,996	114,802,403		59,371,663	
7 STATE INCOME TAX	SIT	(367,279)		(69,527)	(436,806)		(107,315)	(323,676)		(85,641)	
8 RETAIL PRODUCTION PLANT	PRODPLTR	211,351,821		34,338,441	245,690,263		61,100,273	161,732,219		68,469,129	
9 TOTAL kWh AT GEN - ARKANSAS	KWHAR	1,026,042,322		223,116,232	1,249,158,554		573,557,592	1,162,105,893		411,370,112	
10 TOTAL kWh AT GEN - LOUISIANA	KWHLA	0		0	-		0	0		0	
11 TOTAL kWh AT GEN - TEXAS	KWHTX	0		0	-		0	0		0	
12 INTANGIBLE PLANT	INTPLT	10,351,240		2,005,503	12,356,744		2,885,220	8,120,504		3,520,339	
13 DEMPROD RETAIL	DEMRTAIL	0.3460		0.0564	0.4033		0.1003	0.2655		0.1124	
14 FIT TEMPORARY DIFFERENCES	FITTEMP	(3,766,762)		(700,311)	(4,467,073)		(1,095,990)	(2,881,450)		(1,243,328)	
15 Total Depr Expense	DEPEXP	14,913,773		2,745,318	17,659,091		3,983,048	11,013,438		4,880,197	
16 AVAILABLE	AVAIL	0		0	-		0	0		0	
17 Composite Tax Rate (FIT and AR State)	COMPTR	26.1350%		26.1350%	26.1350%		26.1350%	26.1350%		26.1350%	
18 Combined Tax Gross Up (FIT and AR State)	TAX GU	35.3821%		35.3821%	35.3821%		35.3821%	35.3821%		35.3821%	
19 CLAIMED FACTORING	RFACT	0.8613%	0.8613%	0.8613%	0.8613%	0.0460%	0.0460%	0.0460%	0.0460%	0.0460%	0.0460%
20 Gross Revenue Conversion Factor	REVCONV	1.365583	1.008688	1.365583	1.365583	1.000460	1.354444	1.354444	1.000460	1.354444	1.000460
21 AVAILABLE	AVAIL	0		0	-		0	0		0	
SCHEDULE G-4											
RATIO TABLE											
CAPACITY RELATED											
1 PRODUCTION ALLOCATOR	DEMPROD	0.34691		0.05636	0.40327		0.10029	0.26546		0.11238	
2											
3 TRANSMISSION FUNCTION	DEMTRANS	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
4 D. A. ACCT 360 - LAND (MDD)	DEM360DA	0.35572		0.07205	0.42776		0.10335	0.26559		0.12304	
5 D. A. ACCT 361 - STRUCTURES & IMPROVE	DEM361DA	0.35572		0.07205	0.42776		0.10335	0.26559		0.12304	
6 D. A. ACCT 362 - STATION EQUIPMENT	DEM362DA	0.35572		0.07205	0.42776		0.10335	0.26559		0.12304	
7 D. A. ACCT 364 - PRI-POLES, TOWERS & FIX	DEM364DAP	0.35572		0.07205	0.42776		0.10335	0.26559		0.12304	
8 D. A. ACCT 364 - SEC-POLES, TOWERS & FIX	DEM364DAS	0.42370		0.08581	0.50951		-	0.31634		0.14655	
9 D. A. ACCT 365 - PRI - OVRHD COND & DEVICES	DEM365DAP	0.35572		0.07205	0.42776		0.10335	0.26559		0.12304	
10 D. A. ACCT 365 - SEC - OVRHD COND & DEVICES	DEM365DAS	0.42370		0.08581	0.50951		-	0.31634		0.14655	
11 D. A. ACCT 366 - PRI - UNDERGROUND CONDUIT	DEM366DAP	0.35572		0.07205	0.42776		0.10335	0.26559		0.12304	
12 D. A. ACCT 366 - SEC - UNDERGROUND CONDUIT	DEM366DAS	0.42370		0.08581	0.50951		-	0.31634		0.14655	
13 D. A. ACCT 367 - PRI - UNDGRD COND & DEVICE	DEM367DAP	0.35572		0.07205	0.42776		0.10335	0.26559		0.12304	

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	RESIDENTIAL				COMMERCIAL / SMALL INDUSTRIAL					
							LIGHT & POWER				
		BASIC	WITH WATER HEAT	WITH SPACE HEAT	TOTAL RESIDENTIAL	GENERAL UNMETERED	PRI	SEC	PRIMARY SUB	GENERAL SERVICE	C-1 RIDER
		(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
14 D. A. ACCT 367 - SEC - UNDGRD COND & DEVICE	DEM367DAS	0.42370		0.08581	0.50951		-	0.31634		0.14655	
15 D. A. ACCT 368 - LINE TRANSORMERS	DEM368DA	0.35572		0.07205	0.42776		0.10335	0.26559		0.12304	
16 ANNUAL BILLING DEMAND	DEM99	0.00955		0.00274	0.01230		0.17302	0.45264		0.15447	
17 SPP DEMAND	SPPDEMAND	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
18 AVAILABLE-SUBSTATIONS	USERSUB	-		-	-		-	-		-	
19 AVAILABLE-DIR ASSIGN SUBS	USERDASUB	-		-	-		-	-		-	
20 AVAILABLE-PRI OVHD	USEROVHD	-		-	-		-	-		-	
21 AVAILABLE-SECONDARY	USERSEC	-		-	-		-	-		-	
22											
23											
24											
25 COMMODITY RELATED											
26 ------------------------------											
27 FUEL ALLOCATION	FUEL	0.24488		0.05415	0.29903		0.14022	0.28636		0.09865	
28 KWH SALES AT GENERATOR	ENERGY	0.24840		0.05402	0.30241		0.13886	0.28618		0.09959	
29 SALES OF ELECTRICITY - PRESENT FUEL	REVFUEL	-		-	-		-	-		-	
30 KWH SALES AT METER	ENERGY99	0.24593		0.05348	0.29941		0.14132	0.28334		0.09860	
31 MINE CLOSING	MINECLOSE	-		-	-		-	-		-	
32 MINE CLOSING NFIRM RETAIL	MINECLOSEN	-		-	-		-	-		-	
33 NON FIRM FUEL PRESENT FUEL	NFREVFUEL	-		-	-		-	-		-	
34 FUEL ADJUSTMENT	FUELADJ	-		-	-		-	-		-	
35 NON FIRM PROPOSED FUEL RETAIL	NFPROPFUEL	-		-	-		-	-		-	
36 PROPOSED FUEL REVENUE	PROPFUEL	-		-	-		-	-		-	
SCHEDULE G-4											
CUSTOMER RELATED											
------------------------------											
1 ANNUAL AVERAGE CUSTOMERS	CUST99	0.58103		0.09229	0.67332		0.00033	0.01072		0.10687	
2 YEAR END NUMBER OF CUSTOMERS	CUST	0.58103		0.09229	0.67332		0.00033	0.01072		0.10687	
3 WEIGHTED SERVICES	CUST369	0.70265		0.11193	0.81457		0.00111	0.02491		0.15126	
4 WEIGHTED METERS	CUST370	0.57205		0.09089	0.66295		0.02268	0.08606		0.20936	
5 ASSIGNED CUSTOMER INSTALLATIONS	CUST371L	-		-	-		-	-		-	
6 LIGHTING ASSIGNMENTS	CUST373	-		-	-		-	-		-	
7 WEIGHTED METERS	CUST902	0.69303		0.11039	0.80342		0.00052	0.01714		0.17079	
8 CUSTOMER ACCOUNTING	CUST903	0.65863		0.10492	0.76355		0.00037	0.01216		0.12119	
9 CUSTOMER INFO EXP ALLOC	CUSTINFO	0.58103		0.09229	0.67332		0.00033	0.01072		0.10687	
10 CUSTOMER SERVICE EXP ALLOC	CUSTSRVC	0.58103		0.09229	0.67332		0.00033	0.01072		0.10687	
11 ACTIVE CUSTOMER DEPOSITS	CUSTDEPA	-		-	-		-	-		-	
12 CUSTOMERS IN AR & LA	CUSTARLA	0.58103		0.09229	0.67332		0.00033	0.01072		0.10687	
13 RETAIL CUSTOMERS	CUSTRET	0.58103		0.09229	0.67332		0.00033	0.01072		0.10687	
14 AVAILABLE-SERVICE DROP	CUSER1	-		-	-		-	-		-	
15 AVAILABLE-SERVICE DROP	CUSER2	-		-	-		-	-		-	
16 AVAILABLE-METERS	CUSER3	-		-	-		-	-		-	
17 AVAILABLE-METERS	CUSER4	-		-	-		-	-		-	
18 AVAILABLE-CUSTOMER SERVICES	CUSER5	0.69303		0.11039	0.80342		0.00052	0.01714		0.17079	
19 AVAILABLE-CUSTOMER SERVICES	CUSER6	-		-	-		-	-		-	
20 CUSTOMER ENERGY SPLIT 907-916	CUSER7	0.41348		0.07288	0.48636		0.07082	0.14703		0.10273	
21 AVAILABLE-CUSTOMER BILLING	CUSER8	-		-	-		-	-		-	
22 AVAILABLE-CUSTOMER BILLING	CUSER9	0.37130		0.19108	0.56238		0.07290	0.15913		0.11200	
23 AVAILABLE-CUSTOMER LTG AND MISC REV	CUSER10	-		-	-		-	-		-	
24 AVAILABLE-CUSTOMER LTG AND MISC REV											
25 AVAILABLE-CUSTOMER OTHER											
REVENUE RELATED STRINGS											
------------------------------											
29 SALES OF ELECTRICITY-BASE	R408	0.35089		0.06437	0.41526		0.09368	0.23797		0.12230	
30 GROSS RECEIPTS FACTOR	RGR	0.06667		0.06667	0.13333		0.06667	0.06667		0.06667	
31 CLAIMED RATE OF RETURN	ROR	1.00000		1.00000	1.00000		1.00000	1.00000		1.00000	
32 CLAIMED FACTORING	RFACT	2.68736		2.68736	2.68736		0.14353	0.14353		0.14353	
33 PROPOSED REVENUES	PREV	0.35391		0.06492	0.41883		0.09764	0.25389		0.11435	

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	RESIDENTIAL BASIC (7)	RESIDENTIAL WITH WATER HEAT (8)	RESIDENTIAL WITH SPACE HEAT (9)	TOTAL RESIDENTIAL (10)	COMMERCIAL / SMALL INDUSTRIAL GENERAL UNMETERED (11)	LIGHT & POWER PRI (12)	LIGHT & POWER SEC (13)	LIGHT & POWER PRIMARY SUB (14)	GENERAL SERVICE (15)	C-1 RIDER (16)
34 FEDERAL INCOME TAX RATE		1.00000		1.00000	1.00000		1.00000	1.00000		1.00000	
35 LOUISIANA APPORTIONMENT FACTOR		1.00000		1.00000	1.00000		1.00000	1.00000		1.00000	
36 LOUISIANA INCOME TAX RATE		1.00000		1.00000	1.00000		1.00000	1.00000		1.00000	
37 ARKANSAS APPORTIONMENT FACTOR		1.00000		1.00000	1.00000		1.00000	1.00000		1.00000	
38 ARKANSAS INCOME TAX RATE		1.00000		1.00000	1.00000		1.00000	1.00000		1.00000	
SCHEDULE G-4 INTERNALLY DEVELOPED											
1 PRODUCTION PLANT	PRODPLT	0.34691		0.05636	0.40327		0.10029	0.26546		0.11238	
2 PLANT ACCOUNT 352	PLT352	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
3 PLANT ACCOUNT 353	PLT353	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
4 PLANT ACCOUNTS 352 & 353	TRANSUB	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
5 PLANT ACCOUNTS 354, 355 & 356	TRANOHLN	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
6 PLANT ACCOUNT 357	TRANUGLN	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
7 TRANSMISSION PLANT	TRANPLT	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
8 PROD. & TRANS. PLANT	PTPLT	0.33648		0.06047	0.39696		0.10644	0.25484		0.10808	
9 PLANT ACCOUNT 361	PLT361	0.35572		0.07205	0.42776		0.10335	0.26559		0.12304	
10 PLANT ACCOUNT 362	PLT362	0.35572		0.07205	0.42776		0.10335	0.26559		0.12304	
11 PLANT ACCOUNT 368	PLT368	0.35572		0.07205	0.42776		0.10335	0.26559		0.12304	
12 PLANT ACCOUNT 370	PLT370	0.57205		0.09089	0.66295		0.02268	0.08606		0.20936	
13 PLANT ACCOUNT 371	PLT371	-		-	-		-	-		-	
14 PLANT ACCOUNT 373	PLT373	-		-	-		-	-		-	
15 PLANT ACCOUNT 361 & 362	DISTSUB	0.35572		0.07205	0.42776		0.10335	0.26559		0.12304	
16 PLANT ACCOUNT 364 & 365	DISTOHLN	0.37818		0.07659	0.45477		0.06920	0.29236		0.13081	
17 PLANT ACCOUNT 366 & 367	DISTUGLN	0.39161		0.07932	0.47093		0.04878	0.29238		0.13546	
18 DISTRIBUTION PLANT	DISTPLT	0.38336		0.07521	0.45857		0.06926	0.24892		0.12873	
19 TRANS. & DISTR. PLANT	TDPLT	0.35396		0.07113	0.42509		0.09111	0.25599		0.11598	
20 PROD., TRANS., & DISTR. PLANT	PTDPLT	0.35106		0.06505	0.41611		0.09488	0.25989		0.11450	
21 GENERAL PLANT EXCL ADJUSTMENTS	GENPLTX	0.30671		0.05540	0.36211		0.11603	0.27392		0.10716	
22 GENERAL PLANT	GENPLT	0.30671		0.05540	0.36211		0.11603	0.27392		0.10716	
23 TOTAL ELECTRIC PLANT IN SERVICE	PLANT	0.34904		0.06468	0.41373		0.09568	0.26051		0.11421	
24 NET PLANT IN SERVICE	NETPLT	0.34989		0.06600	0.41588		0.09483	0.25962		0.11451	
25 RATE BASE	RBX	0.34958		0.06590	0.41547		0.09507	0.25899		0.11436	
26 OPERATING EXPENSE ACCT NO. 500	OX500	0.32897		0.05593	0.38490		0.10731	0.26923		0.11005	
27 OPERATING EXPENSE ACCT NO. 501	OX501	0.24840		0.05402	0.30241		0.13886	0.28618		0.09959	
28 OPERATING EXPENSE ACCT NO. 502	OX502	0.34691		0.05636	0.40327		0.10029	0.26546		0.11238	
29 OPERATING EXPENSE ACCT NO. 505	OX505	0.34691		0.05636	0.40327		0.10029	0.26546		0.11238	
30 OPERATING EXPENSE ACCT NO. 506	OX506	0.34691		0.05636	0.40327		0.10029	0.26546		0.11238	
31 MAINTENANCE EXPENSE ACCT NO. 510	MX510	0.25830		0.05425	0.31255		0.13498	0.28410		0.10088	
32 MAINTENANCE EXPENSE ACCT NO. 511	MX511	0.34691		0.05636	0.40327		0.10029	0.26546		0.11238	
33 MAINTENANCE EXPENSE ACCT NO. 512	MX512	0.24840		0.05402	0.30241		0.13886	0.28618		0.09959	
34 MAINTENANCE EXPENSE ACCT NO. 513	MX513	0.24840		0.05402	0.30241		0.13886	0.28618		0.09959	
35 MAINTENANCE EXPENSE ACCT NO. 514	MX514	0.34691		0.05636	0.40327		0.10029	0.26546		0.11238	
36 OPERATING EXPENSE ACCT NO. 546	OX546	-		-	-		-	-		-	
37 OPERATING EXPENSE ACCT NO. 548	OX548	0.34691		0.05636	0.40327		0.10029	0.26546		0.11238	
38 OPERATING EXPENSE ACCT NO. 549	OX549	-		-	-		-	-		-	
39 MAINTENANCE EXPENSE ACCT NO. 551	MX551	-		-	-		-	-		-	
40 MAINTENANCE EXPENSE ACCT NO. 552	MX552	-		-	-		-	-		-	
SCHEDULE G-4 INTERNALLY DEVELOPED (CON'T)											
1 MAINTENANCE EXPENSE ACCT NO. 553	MX553	0.34691		0.05636	0.40327		0.10029	0.26546		0.11238	
2 MAINTENANCE EXPENSE ACCT NO. 554	MX554	0.34691		0.05636	0.40327		0.10029	0.26546		0.11238	
3 OPERATING EXPENSE ACCT NO. 556	OX556	0.34691		0.05636	0.40327		0.10029	0.26546		0.11238	
4 OPERATING EXPENSE ACCT NO. 557	OX557	0.34691		0.05636	0.40327		0.10029	0.26546		0.11238	
5 OPERATING EXPENSE ACCT NO. 560	OX560	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
6 OPERATING EXPENSE ACCT NO. 561	OX561	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
7 OPERATING EXPENSE ACCT NO. 562	OX562	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	RESIDENTIAL BASIC (7)	RESIDENTIAL WITH WATER HEAT (8)	RESIDENTIAL WITH SPACE HEAT (9)	TOTAL RESIDENTIAL (10)	GENERAL UNMETERED (11)	LIGHT & POWER PRI (12)	LIGHT & POWER SEC (13)	PRIMARY SUB (14)	COMMERCIAL / SMALL INDUSTRIAL GENERAL SERVICE (15)	C-1 RIDER (16)
8 OPERATING EXPENSE ACCT NO. 563	OX563	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
9 OPERATING EXPENSE ACCT NO. 564	OX564	-		-	-		-	-		-	
10 OPERATING EXPENSE ACCT NO. 565	OX565	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
11 OPERATING EXPENSE ACCT NO. 566	OX566	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
12 MAINTENANCE EXPENSE ACCT NO. 568	MX568	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
13 MAINTENANCE EXPENSE ACCT NO. 569	MX569	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
14 MAINTENANCE EXPENSE ACCT NO. 570	MX570	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
15 MAINTENANCE EXPENSE ACCT NO. 571	MX571	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
16 MAINTENANCE EXPENSE ACCT NO. 572	MX572	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
17 MAINTENANCE EXPENSE ACCT NO. 573	MX573	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
18 OPERATING EXPENSE ACCT NO. 580	OX580	0.40497		0.07626	0.48123		0.05754	0.22130		0.13972	
19 OPERATING EXPENSE ACCT NO. 581	OX581	0.38336		0.07521	0.45857		0.06926	0.24892		0.12873	
20 OPERATING EXPENSE ACCT NO. 582	OX582	0.35572		0.07205	0.42776		0.10335	0.26559		0.12304	
21 OPERATING EXPENSE ACCT NO. 583	OX583	0.37818		0.07659	0.45477		0.06920	0.28236		0.13081	
22 OPERATING EXPENSE ACCT NO. 584	OX584	0.39161		0.07932	0.47093		0.04878	0.29238		0.13546	
23 OPERATING EXPENSE ACCT NO. 585	OX585	-		-	-		-	-		-	
24 OPERATING EXPENSE ACCT NO. 586	OX586	0.57205		0.09089	0.66295		0.02268	0.08606		0.20936	
25 OPERATING EXPENSE ACCT NO. 587	OX587	-		-	-		-	-		-	
26 OPERATING EXPENSE ACCT NO. 588	OX588	0.38336		0.07521	0.45857		0.06926	0.24892		0.12873	
27 OPERATING EXPENSE ACCT NO. 589	OX589	0.38336		0.07521	0.45857		0.06926	0.24892		0.12873	
28 MAINTENANCE EXPENSE ACCT NO. 590	MX590	0.37098		0.07390	0.44488		0.06390	0.26003		0.12889	
29 MAINTENANCE EXPENSE ACCT NO. 591	MX591	0.35572		0.07205	0.42776		0.10335	0.26559		0.12304	
30 MAINTENANCE EXPENSE ACCT NO. 592	MX592	0.35572		0.07205	0.42776		0.10335	0.26559		0.12304	
31 MAINTENANCE EXPENSE ACCT NO. 593	MX593	0.37818		0.07659	0.45477		0.06920	0.28236		0.13081	
32 MAINTENANCE EXPENSE ACCT NO. 594	MX594	0.39161		0.07932	0.47093		0.04878	0.29238		0.13546	
33 MAINTENANCE EXPENSE ACCT NO. 595	MX595	0.35572		0.07205	0.42776		0.10335	0.26559		0.12304	
34 MAINTENANCE EXPENSE ACCT NO. 596	MX596	-		-	-		-	-		-	
35 MAINTENANCE EXPENSE ACCT NO. 597	MX597	0.57205		0.09089	0.66295		0.02268	0.08606		0.20936	
36 MAINTENANCE EXPENSE ACCT NO. 598	MX598	-		-	-		-	-		-	
37 OPERATING EXPENSE ACCT NO. 901	OX901	0.68357		0.09958	0.78315		0.00037	0.01217		0.12130	
38 OPERATING EXPENSE ACCT NO. 902	OX902	0.69303		0.11039	0.80342		0.00052	0.01714		0.17079	
39 OPERATING EXPENSE ACCT NO. 903	OX903	0.68197		0.09775	0.77972		0.00034	0.01133		0.11290	
40 OPERATING EXPENSE ACCT NO. 904	OX904	0.35089		0.06437	0.41526		0.09368	0.23797		0.12230	
SCHEDULE G-4 INTERNALLY DEVELOPED (CON'T)											
1 OPERATING EXPENSE ACCT NO. 905	OX905	0.68357		0.09958	0.78315		0.00037	0.01217		0.12130	
2 OPERATING EXPENSE ACCT NO. 907	OX907	0.41348		0.07288	0.48636		0.07082	0.14703		0.10273	
3 OPERATING EXPENSE ACCT NO. 908	OX908	0.41348		0.07288	0.48636		0.07082	0.14703		0.10273	
4 OPERATING EXPENSE ACCT NO. 909	OX909	0.41348		0.07288	0.48636		0.07082	0.14703		0.10273	
5 OPERATING EXPENSE ACCT NO. 910	OX910	0.41348		0.07288	0.48636		0.07082	0.14703		0.10273	
6 OPERATING EXPENSE ACCT NO. 911	OX911	0.41348		0.07288	0.48636		0.07082	0.14703		0.10273	
7 OPERATING EXPENSE ACCT NO. 912	OX912	0.41348		0.07288	0.48636		0.07082	0.14703		0.10273	
8 OPERATING EXPENSE ACCT NO. 913	OX913	0.41348		0.07288	0.48636		0.07082	0.14703		0.10273	
9 OPERATING EXPENSE ACCT NO. 916	OX916	-		-	-		-	-		-	
10 OPERATING EXPENSE ACCT NO. 920	OX920	0.38063		0.06773	0.44836		0.08526	0.22492		0.11501	
11 OPERATING EXPENSE ACCT NO. 921	OX921	0.38063		0.06773	0.44836		0.08526	0.22492		0.11501	
12 OPERATING EXPENSE ACCT NO. 922	OX922	0.38063		0.06773	0.44836		0.08526	0.22492		0.11501	
13 OPERATING EXPENSE ACCT NO. 923	OX923	0.38063		0.06773	0.44836		0.08526	0.22492		0.11501	
14 1/8 O&M LESS FUEL & PURCHASED PWR	OMX	0.35608		0.06678	0.42285		0.09626	0.24417		0.11128	
15 DEPRECIATION EXPENSE	DEPREXP	0.35197		0.06479	0.41676		0.09400	0.25992		0.11517	
16 AD VALOREM TAXES	PROPTAX	0.34904		0.06468	0.41373		0.09568	0.26051		0.11421	
17 LABOR ACCOUNTS 501 THRU 507	LAB501_507	0.32897		0.05593	0.38490		0.10731	0.26923		0.11005	
18 LABOR ACCOUNTS 511 THRU 514	LAB511_514	0.25830		0.05425	0.31255		0.13498	0.28410		0.10088	
19 LABOR ACCOUNTS 547 THRU 550	LAB547_550	0.34691		0.05636	0.40327		0.10029	0.26546		0.11238	
20 LABOR ACCOUNTS 552 THRU 554	LAB552_554	0.34691		0.05636	0.40327		0.10029	0.26546		0.11238	
21 LABOR ACCOUNTS 561 THRU 567	LAB561_567	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
22 LABOR ACCOUNTS 569 THRU 573	LAB569_573	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
23 LABOR ACCOUNTS 581 THRU 589	LAB581_589	0.40497		0.07626	0.48123		0.05754	0.22130		0.13972	

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		RESIDENTIAL				COMMERCIAL / SMALL INDUSTRIAL					
							LIGHT & POWER				
	ALLOC	BASIC	WITH WATER HEAT	WITH SPACE HEAT	TOTAL RESIDENTIAL	GENERAL UNMETERED	PRI	SEC	PRIMARY SUB	GENERAL SERVICE	C-1 RIDER
		(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
24 LABOR ACCOUNTS 591 THRU 598	LAB591_598	0.37098		0.07390	0.44488		0.06390	0.26003		0.12889	
25 LABOR ACCOUNTS 902 THRU 905	LAB902_905	0.68357		0.09958	0.78315		0.00037	0.01217		0.12130	
26 LABOR ACCOUNTS 908 THRU 910	LAB908_910	0.41348		0.07288	0.48636		0.07082	0.14703		0.10273	
27 LABOR ACCOUNTS 912 THRU 916	LAB912_916	0.41348		0.07288	0.48636		0.07082	0.14703		0.10273	
28 PAYROLL EXCLUDING A&G	LABORX	0.38184		0.06786	0.44970		0.08501	0.22404		0.11559	
29 RETAIL PAYROLL EXCLUDING A&G	LABORXR	0.38184		0.06786	0.44970		0.08501	0.22404		0.11559	
30 TOTAL PAYROLL	LABORT	0.38063		0.06773	0.44836		0.08526	0.22492		0.11501	
31 ACCT 903 EXCL BILLING	OX903X	-		-	-		-	-		-	
32 ACCT 903 BILLING	OX903B	0.68197		0.09775	0.77972		0.00034	0.01133		0.11290	
33 PRODUCTION LABOR	LABPROD	0.30671		0.05540	0.36211		0.11603	0.27392		0.10716	
34 TRANSMISSION LABOR	LABTRAN	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
35 DISTR LABOR EXCL METERING	LABDIST	0.36895		0.07333	0.44228		0.06478	0.25457		0.12594	
36 CUST SERVICE LABOR EXCL METER & BILLING	LABCUSSV	0.58808		0.08912	0.67721		0.02501	0.05885		0.10970	
37 METERING LABOR	LABMETER	0.61352		0.09758	0.71110		0.01508	0.06244		0.19614	
38 BILLING LABOR	LABBILL	-		-	-		-	-		-	

SCHEDULE G-4
INTERNALLY DEVELOPED (CON'T)

	ALLOC	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
1 SALES REVENUE	REVSALES	0.35089		0.06437	0.41526		0.09368	0.23797		0.12230	
2 0.5*PRODPLT + 0.95*TDPLT	PTDPLTW	0.35206		0.06716	0.41922		0.09358	0.25854		0.11501	
3 REV DEF @ CLAIMED * FACTORING	FACTC	-		-	-		-	-		-	
4 REV DEF @ PROPOSED * FACTORING	FACTP	-		-	-		-	-		-	
5 COS @ CLAIMED * AR REV REL TAX	REVFACC1	0.06667		0.06667	0.13333		0.06667	0.06667		0.06667	
6 COS @ CLAIMED * LA REV RELA TAX	REVFACC2	-		-	-		-	-		-	
7 COS @ CLAIMED * TX REV REL TAX	REVFACC3	-		-	-		-	-		-	
8 PROPOSED REV * AR REV REL TX	REVFACP1	0.06667		0.06667	0.13333		0.06667	0.06667		0.06667	
9 PROPOSED REV * LA REV REL TAX	REVFACP2	-		-	-		-	-		-	
10 PROPOSED REV * TX REV REL TAX	REVFACP3	-		-	-		-	-		-	
11 FUEL - RETAIL	FUELR	0.24840		0.05402	0.30241		0.13886	0.28618		0.09959	
12 FUEL - WHOLESALE	FUELW	-		-	-		-	-		-	
13 SALES REVENUE - RETAIL	REVSALESR	0.35089		0.06437	0.41526		0.09368	0.23797		0.12230	
14 SALES REVENUE - WHOLESALE	REVSALESW	-		-	-		-	-		-	
15 SALES REVENUE - ARKANSAS	REVSALEAR	0.35089		0.06437	0.41526		0.09368	0.23797		0.12230	
16 SALES REVENUE - LOUISIANA	REVSALELA	-		-	-		-	-		-	
17 SALES REVENUE - TEXAS	REVSALETX	-		-	-		-	-		-	
18 PRODUCTION PLANT - TEXAS	PRODPLTTX	-		-	-		-	-		-	
19 DISTRIBUTION PLANT - LOUISIANA	DISTPLTLA	-		-	-		-	-		-	
20 RETAIL REVENUE LA	RREVLA	-		-	-		-	-		-	
21 TAXABLE INCOME LA	TAXINCLA	-		-	-		-	-		-	
22 TAXABLE INCOME AR	TAXINCAR	0.35333		0.06695	0.42028		0.10354	0.31365		0.08101	
23 PLANT LA	PLANTLA	-		-	-		-	-		-	
24 PLANT AR	PLANTAR	0.34904		0.06468	0.41373		0.09568	0.26051		0.11421	
25 DEMAND PROD WHOLESALE	DPRODWH	-		-	-		-	-		-	
26 DEMAND PROD ARKANSAS	DPRODAR	0.34691		0.05636	0.40327		0.10029	0.26546		0.11238	
27 DEMAND PROD LOUISIANA	DPRODLA	-		-	-		-	-		-	
28 DEMAND PROD TEXAS	DPRODTX	-		-	-		-	-		-	
29 DEMAND TRAN WHOLESALE	DTRANWH	-		-	-		-	-		-	
30 DEMAND TRAN ARKANSAS	DTRANAR	0.32105		0.06657	0.38761		0.11556	0.26392		0.10170	
31 DEMAND TRAN LOUISIANA	DTRANLA	-		-	-		-	-		-	
32 DEMAND TRAN TEXAS	DTRANTX	-		-	-		-	-		-	
33 DEMAND DIST WHOLESALE	DDISTWH	-		-	-		-	-		-	
34 DEMAND DIST ARKANSAS	DDISTAR	0.38336		0.07521	0.45857		0.06926	0.24892		0.12873	
35 DEMAND DIST LOUISIANA	DDISTLA	-		-	-		-	-		-	
36 DEMAND DIST TEXAS	DDISTTX	-		-	-		-	-		-	
37 DEMAND GENERAL WHOLESALE	DGENLWH	-		-	-		-	-		-	
38 DEMAND GENERAL ARKANSAS	DGENLAR	0.30671		0.05640	0.36211		0.11603	0.27392		0.10716	
39 DEMAND GENERAL LOUISIANA	DGENLLA	-		-	-		-	-		-	

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	RESIDENTIAL				COMMERCIAL / SMALL INDUSTRIAL					
							LIGHT & POWER				
		BASIC	WITH WATER HEAT	WITH SPACE HEAT	TOTAL RESIDENTIAL	GENERAL UNMETERED	PRI	SEC	PRIMARY SUB	GENERAL SERVICE	C-1 RIDER
		(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
40 DEMAND GENERAL TEXAS	DGENLTX	-		-	-		-	-		-	
SCHEDULE G-4 INTERNALLY DEVELOPED (CON'T)											
1 PRODUCTION PLANT - TEXAS RETAIL	PRODPLTT	-		-	-		-	-		-	
2 LABOR 902 & 903	LAB902_903	0.68357		0.09958	0.78315		0.00037	0.01217		0.12130	
3 SALES REVENUE - AR RETAIL	RVSALEARR	0.35089		0.06437	0.41526		0.09368	0.23797		0.12230	
4 SALES REVENUE - LA RETAIL	RVSALELAR	-		-	-		-	-		-	
5 SALES REVENUE - TX RETAIL	RVSALETXR	-		-	-		-	-		-	
6 DIST PLANT BEFORE CONTRA ADJ	DISTPLTX	0.38336		0.07521	0.45857		0.06926	0.24892		0.12873	
7 STATE INCOME TAX	SIT	0.35313		0.06685	0.41998		0.10318	0.31121		0.08253	
8 RETAIL PRODUCTION PLANT	PRODPLTR	0.34691		0.05636	0.40327		0.10029	0.26546		0.11238	
9 TOTAL kWh AT GEN - ARKANSAS	KWHAR	0.24840		0.05402	0.30241		0.13886	0.28618		0.09959	
10 TOTAL kWh AT GEN- LOUISIANA	KWHLA	-		-	-		-	-		-	
11 TOTAL kWh AT GEN- TEXAS	KWHTX	-		-	-		-	-		-	
12 INTANGIBLE PLANT	INTPLT	0.33623		0.06514	0.40137		0.09372	0.26377		0.11435	
13 DEMPROD RETAIL	DEMRTAIL	0.34691		0.05636	0.40327		0.10029	0.26546		0.11238	
14 FIT TEMPORARY DIFFERENCES	FITTEMP	0.34156		0.06350	0.40506		0.09938	0.26128		0.11274	
15 Total Depr Expense	DEPEXP	0.35197		0.06479	0.41676		0.09400	0.25992		0.11517	
16 AVAILABLE	AVAIL	-		-	-		-	-		-	
17 Composite Tax Rate (FIT and AR State)	COMPTR	1.00000		1.00000	1.00000		1.00000	1.00000		1.00000	
18 Combined Tax Gross Up (FIT and AR State)	TAX GU	1.00000		1.00000	1.00000		1.00000	1.00000		1.00000	
19 CLAIMED FACTORING	RFACT	2.68736		2.68736	2.68736		0.14353	0.14353		0.14353	
20 Gross Revenue Conversion Factor	REVCONV	1.00545		1.00545	1.00545		0.99725	0.99725		0.99725	
21 AVAILABLE	AVAIL	-		-	-		-	-		-	
22 AVAILABLE	AVAIL	-		-	-		-	-		-	

Supporting Schedules
(a) G-5.1 or G-5.2
(b) H-1
WP's G-2
WP's G-2 and G-3
G Class WP

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	LIGHT & POWER TOU			LARGE INDUSTRIAL					
					LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
		SEC (17)	PRI (18)	TOTAL (19)	PRI (20)	69 KV (21)	TOTAL (22)	INDUSTRIAL (23)	CURTAILABLE (24)	TOTAL (25)
SCHEDULE G-4										
ALLOCATION FACTOR TABLE										
CAPACITY RELATED										
1 PRODUCTION ALLOCATOR	DEMPROD	0.00110	[redacted]	0.00327	0.03817	[redacted]	0.06143	[redacted]	0.00509	0.04437
2			[redacted]			[redacted]		[redacted]		
3 TRANSMISSION FUNCTION	DEMTRANS	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
4 D. A. ACCT 360 - LAND (MDO)	DEM360DA	3,687	[redacted]	6,833	40,969	[redacted]	40,969	[redacted]	12,079	12,079
5 D. A. ACCT 361 - STRUCTURES & IMPROVE	DEM361DA	3,687	[redacted]	6,833	40,969	[redacted]	40,969	[redacted]	12,079	12,079
6 D. A. ACCT 362 - STATION EQUIPMENT	DEM362DA	3,687	[redacted]	6,833	40,969	[redacted]	40,969	[redacted]	12,079	12,079
7 D. A. ACCT 364 - PRI-POLES, TOWERS & FIX	DEM364DAP	3,687	[redacted]	6,833	40,969	[redacted]	40,969	[redacted]	12,079	12,079
8 D. A. ACCT 364 - SEC-POLES, TOWERS & FIX	DEM364DAS	3,687	[redacted]	3,687	-	[redacted]	-	[redacted]	-	-
9 D. A. ACCT 365 - PRI - OVRHD COND & DEVICES	DEM365DAP	3,687	[redacted]	6,833	40,969	[redacted]	40,969	[redacted]	12,079	12,079
10 D. A. ACCT 365 - SEC - OVRHD COND & DEVICES	DEM365DAS	3,687	[redacted]	3,687	-	[redacted]	-	[redacted]	-	-
11 D. A. ACCT 366 - PRI - UNDERGROUND CONDUIT	DEM366DAP	3,687	[redacted]	6,833	40,969	[redacted]	40,969	[redacted]	12,079	12,079
12 D. A. ACCT 366 - SEC- UNDERGROUND CONDUIT	DEM366DAS	3,687	[redacted]	3,687	-	[redacted]	-	[redacted]	-	-
13 D. A. ACCT 367 - PRI - UNDGRD COND & DEVICE	DEM367DAP	3,687	[redacted]	6,833	40,969	[redacted]	40,969	[redacted]	12,079	12,079
14 D. A. ACCT 367 - SEC - UNDGRD COND & DEVICE	DEM367DAS	3,687	[redacted]	3,687	-	[redacted]	-	[redacted]	-	-
15 D. A. ACCT 368 - LINE TRANSORMERS	DEM368DA	3,687	[redacted]	6,833	40,969	[redacted]	40,969	[redacted]	12,079	12,079
16 ANNUAL BILLING DEMAND	DEM99	32,677	[redacted]	65,099	344,769	[redacted]	607,413	[redacted]	171,091	637,112
17 SPP DEMAND	SPPDEMAND	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
18 AVAILABLE SUBSTATIONS	USERSUB	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
19 AVAILABLE DIR ASSIGN SUBS	USERDASUB	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
20 AVAILABLE-PRI OVHD	USEROVHD	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
21 AVAILABLE-SECONDARY	USERSEC	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
22			[redacted]			[redacted]		[redacted]		
23			[redacted]			[redacted]		[redacted]		
24			[redacted]			[redacted]		[redacted]		
25 COMMODITY RELATED			[redacted]			[redacted]		[redacted]		
26			[redacted]			[redacted]		[redacted]		
27 FUEL ALLOCATION	FUEL	202,293	[redacted]	715,847	5,358,734	[redacted]	10,188,783	[redacted]	892,701	8,399,388
28 KWH SALES AT GENERATOR	ENERGY	6,761,775	[redacted]	24,440,791	183,290,750	[redacted]	344,305,546	[redacted]	30,246,977	281,396,933
29 SALES OF ELECTRICITY - PRESENT FUEL	REVFUEL	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
30 KWH SALES AT METER	ENERGY99	6,267,577	[redacted]	23,099,124	174,504,451	[redacted]	330,671,812	[redacted]	28,797,046	272,386,000
31 MINE CLOSING	MINECLOSE	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
32 MINE CLOSING NFIRM RETAIL	MINECLOSEN	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
33 NON FIRM FUEL PRESENT FUEL	NFREVFUEL	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
34 FUEL ADJUSTMENT	FUELADJ	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
35 NON FIRM PROPOSED FUEL RETAIL	NFPROPFUEL	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
36 PROPOSED FUEL REVENUE	PROPFUEL	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
SCHEDULE G-4			[redacted]			[redacted]		[redacted]		
CUSTOMER RELATED			[redacted]			[redacted]		[redacted]		
1 ANNUAL AVERAGE CUSTOMERS	CUST99	2	[redacted]	3	2	[redacted]	3	[redacted]	5	6
2 YEAR END NUMBER OF CUSTOMERS	CUST	2	[redacted]	3	2	[redacted]	3	[redacted]	5	6
3 WEIGHTED SERVICES	CUST369	6	[redacted]	9	6	[redacted]	6	[redacted]	15	15
4 WEIGHTED METERS	CUST370	19	[redacted]	87	136	[redacted]	542	[redacted]	341	748
5 ASSIGNED CUSTOMER INSTALLATIONS	CUST371L	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
6 LIGHTING ASSIGNMENTS	CUST373	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
7 WEIGHTED METERS	CUST902	3	[redacted]	4	2	[redacted]	3	[redacted]	7	8
8 CUSTOMER ACCOUNTING	CUST903	1,512	[redacted]	2,316	2,701	[redacted]	3,795	[redacted]	3,539	6,595
9 CUSTOMER INFO EXP ALLOC	CUSTINFO	2	[redacted]	3	2	[redacted]	3	[redacted]	5	6
10 CUSTOMER SERVICE EXP ALLOC	CUSTSRVC	2	[redacted]	3	2	[redacted]	3	[redacted]	5	6
11 ACTIVE CUSTOMER DEPOSITS	CUSTDEPA	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
12 CUSTOMERS IN AR & LA	CUSTARLA	2	[redacted]	3	2	[redacted]	3	[redacted]	5	6
13 RETAIL CUSTOMERS	CUSTRET	2	[redacted]	3	2	[redacted]	3	[redacted]	5	6
14 AVAILABLE SERVICE DROP	CUSER1	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
15 AVAILABLE-SERVICE DROP	CUSER2	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
16 AVAILABLE-METERS	CUSER3	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

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CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	LIGHT & POWER TOU			LARGE INDUSTRIAL					
					LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
		SEC (17)	PRI (18)	TOTAL (19)	PRI (20)	69 KV (21)	TOTAL (22)	INDUSTRIAL (23)	CURTAILABLE (24)	TOTAL (25)
17 AVAILABLE-METERS	CUSER4	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
18 AVAILABLE-CUSTOMER SERVICES	CUSER5	3	[redacted]	4	2	[redacted]	3	[redacted]	7	8
19 AVAILABLE-CUSTOMER SERVICES	CUSER6	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
20 CUSTOMER ENERGY SPLIT 907-916	CUSER7	0.00082	[redacted]	0.00300	0.02257	[redacted]	0.04276	[redacted]	0.00374	0.03524
21 AVAILABLE-CUSTOMER BILLING	CUSER8	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
22 AVAILABLE-CUSTOMER BILLING	CUSER9	0	[redacted]	0	0	[redacted]	0	[redacted]	-	0
23 AVAILABLE-CUSTOMER LTG AND MISC REV	CUSER10	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
24 AVAILABLE-CUSTOMER LTG AND MISC REV	CUSER11	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
25 AVAILABLE-CUSTOMER OTHER	CUSER12	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
26			[redacted]			[redacted]		[redacted]		
27 REVENUE RELATED STRINGS			[redacted]			[redacted]		[redacted]		
28 --			[redacted]			[redacted]		[redacted]		
29 SALES OF ELECTRICITY-BASE	R40B	248,498	[redacted]	435,558	3,731,299	[redacted]	5,927,210	[redacted]	966,899	5,221,554
30 GROSS RECEIPTS FACTOR	RGR	0.0000	[redacted]	0.0000	0.0000	[redacted]	0.0000	[redacted]	0.0000	0.0000
31 CLAIMED RATE OF RETURN	ROR	0.0521	[redacted]	0.0521	0.0521	[redacted]	0.0521	[redacted]	0.0521	0.0521
32 CLAIMED FACTORING	RFACT	0.000460	[redacted]	0.000460	0.000090	[redacted]	0.000090	[redacted]	0.000090	0.000090
33 PROPOSED REVENUES	PREV	553,854	[redacted]	970,809	6,132,635	[redacted]	9,949,545	[redacted]	1,832,894	8,081,957
34 FEDERAL INCOME TAX RATE		0.21000	[redacted]	0.21000	0.21000	[redacted]	0.21000	[redacted]	0.21000	0.21000
35 LOUISIANA APPORTIONMENT FACTOR		0.24386	[redacted]	0.24386	0.24386	[redacted]	0.24386	[redacted]	0.24386	0.24386
36 LOUISIANA INCOME TAX RATE		0.06500	[redacted]	0.06500	0.06500	[redacted]	0.06500	[redacted]	0.06500	0.06500
37 ARKANSAS APPORTIONMENT FACTOR		0.24386	[redacted]	0.24386	0.24386	[redacted]	0.24386	[redacted]	0.24386	0.24386
38 ARKANSAS INCOME TAX RATE		0.06500	[redacted]	0.06500	0.06500	[redacted]	0.06500	[redacted]	0.06500	0.06500
SCHEDULE G-4 INTERNALLY DEVELOPED			[redacted]			[redacted]		[redacted]		
1 PRODUCTION PLANT	PRODPLT	667,127	[redacted]	1,992,851	23,256,828	[redacted]	37,424,283	[redacted]	3,099,245	27,034,775
2 PLANT ACCOUNT 352	PLT352	4,735	[redacted]	13,028	132,145	[redacted]	231,129	[redacted]	24,963	181,513
3 PLANT ACCOUNT 353	PLT353	196,906	[redacted]	541,703	5,494,774	[redacted]	9,610,640	[redacted]	1,037,986	7,547,536
4 PLANT ACCOUNTS 352 & 353	TRANSUB	201,642	[redacted]	554,730	5,626,920	[redacted]	9,841,769	[redacted]	1,062,949	7,729,049
5 PLANT ACCOUNTS 354, 355 & 356	TRANOHLN	343,868	[redacted]	946,005	9,505,820	[redacted]	16,783,578	[redacted]	1,812,690	13,180,669
6 PLANT ACCOUNT 357	TRANUGLN	666	[redacted]	1,832	18,579	[redacted]	32,496	[redacted]	3,510	25,520
7 TRANSMISSION PLANT	TRANPLT	577,630	[redacted]	1,589,100	16,119,075	[redacted]	28,193,083	[redacted]	3,044,961	22,140,911
8 PROD. & TRANS. PLANT	PTPLT	1,244,757	[redacted]	3,581,951	39,375,903	[redacted]	65,617,366	[redacted]	6,144,206	49,175,686
9 PLANT ACCOUNT 361	PLT361	9,436	[redacted]	17,485	104,844	[redacted]	104,844	[redacted]	30,913	30,913
10 PLANT ACCOUNT 362	PLT362	303,230	[redacted]	561,929	3,369,375	[redacted]	3,369,375	[redacted]	993,451	993,451
11 PLANT ACCOUNT 368	PLT368	223,427	[redacted]	414,043	2,482,639	[redacted]	2,482,639	[redacted]	731,999	731,999
12 PLANT ACCOUNT 370	PLT370	2,302	[redacted]	10,541	16,478	[redacted]	65,671	[redacted]	41,317	90,630
13 PLANT ACCOUNT 371	PLT371	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
14 PLANT ACCOUNT 373	PLT373	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
15 PLANT ACCOUNT 361 & 362	DISTSUB	312,665	[redacted]	579,415	3,474,220	[redacted]	3,474,220	[redacted]	1,024,364	1,024,364
16 PLANT ACCOUNT 364 & 365	DISTOHLN	736,962	[redacted]	1,132,960	5,157,592	[redacted]	5,157,592	[redacted]	1,520,702	1,520,702
17 PLANT ACCOUNT 366 & 367	DISTUGLN	305,556	[redacted]	417,322	1,455,667	[redacted]	1,455,667	[redacted]	429,200	429,200
18 DISTRIBUTION PLANT	DISTPLT	1,569,790	[redacted]	2,570,964	12,682,622	[redacted]	12,731,736	[redacted]	3,778,146	3,827,381
19 TRANS. & DISTR. PLANT	TDPLT	2,167,420	[redacted]	4,160,064	28,801,698	[redacted]	40,924,819	[redacted]	6,823,107	25,968,291
20 PROD., TRANS., & DISTR. PLANT	PTDPLT	2,834,547	[redacted]	6,152,914	52,058,525	[redacted]	78,349,102	[redacted]	9,922,352	53,003,067
21 GENERAL PLANT EXCL ADJUSTMENTS	GENPLTX	80,453	[redacted]	265,948	2,488,062	[redacted]	4,301,801	[redacted]	366,718	3,304,886
22 GENERAL PLANT	GENPLT	80,453	[redacted]	265,948	2,488,062	[redacted]	4,301,801	[redacted]	366,718	3,304,886
23 TOTAL ELECTRIC PLANT IN SERVICE	PLANT	2,985,855	[redacted]	6,566,148	55,502,990	[redacted]	84,213,833	[redacted]	10,503,782	57,352,683
24 NET PLANT IN SERVICE	NETPLT	2,026,983	[redacted]	4,318,102	35,072,829	[redacted]	52,535,376	[redacted]	6,950,759	35,363,464
25 RATE BASE	RBX	2,397,323	[redacted]	5,133,310	41,248,667	[redacted]	62,104,772	[redacted]	8,207,547	42,128,577
26 OPERATING EXPENSE ACCT NO. 500	OX500	4,113	[redacted]	12,931	135,425	[redacted]	225,420	[redacted]	18,931	167,804
27 OPERATING EXPENSE ACCT NO. 501	OX501	5,588	[redacted]	20,197	151,467	[redacted]	284,525	[redacted]	24,995	232,539
28 OPERATING EXPENSE ACCT NO. 502	OX502	3,318	[redacted]	9,912	115,680	[redacted]	186,149	[redacted]	15,416	134,472
29 OPERATING EXPENSE ACCT NO. 505	OX505	1,297	[redacted]	3,876	45,228	[redacted]	72,780	[redacted]	6,027	52,575
30 OPERATING EXPENSE ACCT NO. 506	OX506	4,416	[redacted]	13,190	153,935	[redacted]	247,706	[redacted]	20,514	178,941
31 MAINTENANCE EXPENSE ACCT NO. 510	MX510	1,483	[redacted]	5,296	41,005	[redacted]	76,059	[redacted]	6,653	61,613
32 MAINTENANCE EXPENSE ACCT NO. 511	MX511	604	[redacted]	1,805	21,060	[redacted]	33,889	[redacted]	2,807	24,481
33 MAINTENANCE EXPENSE ACCT NO. 512	MX512	13,192	[redacted]	47,684	357,598	[redacted]	671,735	[redacted]	59,011	549,001
34 MAINTENANCE EXPENSE ACCT NO. 513	MX513	1,606	[redacted]	5,812	43,588	[redacted]	81,879	[redacted]	7,193	66,919

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

		LIGHT & POWER TOU			LARGE INDUSTRIAL					
					LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
	ALLOC	SEC (17)	PRI (18)	TOTAL (19)	PRI (20)	69 KV (21)	TOTAL (22)	INDUSTRIAL (23)	CURTAILABLE (24)	TOTAL (25)
35 MAINTENANCE EXPENSE ACCT NO. 514	MX514	874	[redacted]	2,611	30,474	[redacted]	49,038	[redacted]	4,061	35,424
36 OPERATING EXPENSE ACCT NO. 546	OX546	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
37 OPERATING EXPENSE ACCT NO. 548	OX548	135	[redacted]	404	4,718	[redacted]	7,592	[redacted]	629	5,484
38 OPERATING EXPENSE ACCT NO. 549	OX549	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
39 MAINTENANCE EXPENSE ACCT NO. 551	MX551	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
40 MAINTENANCE EXPENSE ACCT NO. 552	MX552	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
SCHEDULE G-4 INTERNALLY DEVELOPED (CON'T)										
1 MAINTENANCE EXPENSE ACCT NO. 553	MX553	135	[redacted]	403	4,705	[redacted]	7,571	[redacted]	627	5,469
2 MAINTENANCE EXPENSE ACCT NO. 554	MX554	4	[redacted]	11	126	[redacted]	202	[redacted]	17	146
3 OPERATING EXPENSE ACCT NO. 556	OX556	409	[redacted]	1,223	14,267	[redacted]	22,958	[redacted]	1,901	16,585
4 OPERATING EXPENSE ACCT NO. 557	OX557	786	[redacted]	2,349	27,414	[redacted]	44,114	[redacted]	3,653	31,868
5 OPERATING EXPENSE ACCT NO. 560	OX560	2,131	[redacted]	5,863	59,472	[redacted]	104,020	[redacted]	11,235	81,690
6 OPERATING EXPENSE ACCT NO. 561	OX561	4,112	[redacted]	11,314	114,760	[redacted]	200,721	[redacted]	21,679	157,632
7 OPERATING EXPENSE ACCT NO. 562	OX562	154	[redacted]	424	4,300	[redacted]	7,521	[redacted]	812	5,906
8 OPERATING EXPENSE ACCT NO. 563	OX563	122	[redacted]	335	3,393	[redacted]	5,935	[redacted]	641	4,661
9 OPERATING EXPENSE ACCT NO. 564	OX564	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
10 OPERATING EXPENSE ACCT NO. 565	OX565	30,310	[redacted]	83,384	845,805	[redacted]	1,479,356	[redacted]	159,776	1,161,785
11 OPERATING EXPENSE ACCT NO. 566	OX566	561	[redacted]	1,543	15,656	[redacted]	27,384	[redacted]	2,958	21,505
12 MAINTENANCE EXPENSE ACCT NO. 568	MX568	12	[redacted]	32	329	[redacted]	576	[redacted]	62	452
13 MAINTENANCE EXPENSE ACCT NO. 569	MX569	164	[redacted]	452	4,586	[redacted]	8,022	[redacted]	866	6,300
14 MAINTENANCE EXPENSE ACCT NO. 570	MX570	1,009	[redacted]	2,776	28,162	[redacted]	49,257	[redacted]	5,320	38,683
15 MAINTENANCE EXPENSE ACCT NO. 571	MX571	2,961	[redacted]	8,146	82,631	[redacted]	144,525	[redacted]	15,609	113,500
16 MAINTENANCE EXPENSE ACCT NO. 572	MX572	0	[redacted]	1	8	[redacted]	13	[redacted]	1	10
17 MAINTENANCE EXPENSE ACCT NO. 573	MX573	11	[redacted]	30	307	[redacted]	538	[redacted]	58	422
18 OPERATING EXPENSE ACCT NO. 580	OX580	1,399	[redacted]	2,233	10,395	[redacted]	10,646	[redacted]	3,252	3,504
19 OPERATING EXPENSE ACCT NO. 581	OX581	22	[redacted]	35	173	[redacted]	173	[redacted]	51	52
20 OPERATING EXPENSE ACCT NO. 582	OX582	388	[redacted]	719	4,308	[redacted]	4,308	[redacted]	1,270	1,270
21 OPERATING EXPENSE ACCT NO. 583	OX583	2,400	[redacted]	3,690	16,798	[redacted]	16,798	[redacted]	4,953	4,953
22 OPERATING EXPENSE ACCT NO. 584	OX584	2,097	[redacted]	2,864	9,989	[redacted]	9,989	[redacted]	2,945	2,945
23 OPERATING EXPENSE ACCT NO. 585	OX585	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
24 OPERATING EXPENSE ACCT NO. 586	OX586	87	[redacted]	397	621	[redacted]	2,473	[redacted]	1,556	3,413
25 OPERATING EXPENSE ACCT NO. 587	OX587	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
26 OPERATING EXPENSE ACCT NO. 588	OX588	13,170	[redacted]	21,298	105,062	[redacted]	105,469	[redacted]	31,298	31,706
27 OPERATING EXPENSE ACCT NO. 589	OX589	612	[redacted]	990	4,885	[redacted]	4,904	[redacted]	1,455	1,474
28 MAINTENANCE EXPENSE ACCT NO. 590	MX590	263	[redacted]	406	1,845	[redacted]	1,854	[redacted]	551	561
29 MAINTENANCE EXPENSE ACCT NO. 591	MX591	25	[redacted]	47	279	[redacted]	279	[redacted]	82	82
30 MAINTENANCE EXPENSE ACCT NO. 592	MX592	619	[redacted]	1,146	6,873	[redacted]	6,873	[redacted]	2,026	2,026
31 MAINTENANCE EXPENSE ACCT NO. 593	MX593	19,141	[redacted]	29,426	133,955	[redacted]	133,955	[redacted]	39,496	39,496
32 MAINTENANCE EXPENSE ACCT NO. 594	MX594	999	[redacted]	1,365	4,761	[redacted]	4,761	[redacted]	1,404	1,404
33 MAINTENANCE EXPENSE ACCT NO. 595	MX595	74	[redacted]	137	820	[redacted]	820	[redacted]	242	242
34 MAINTENANCE EXPENSE ACCT NO. 596	MX596	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
35 MAINTENANCE EXPENSE ACCT NO. 597	MX597	12	[redacted]	55	85	[redacted]	340	[redacted]	214	470
36 MAINTENANCE EXPENSE ACCT NO. 598	MX598	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
37 OPERATING EXPENSE ACCT NO. 901	OX901	1,477	[redacted]	2,262	2,637	[redacted]	3,705	[redacted]	3,456	6,440
38 OPERATING EXPENSE ACCT NO. 902	OX902	11	[redacted]	15	8	[redacted]	11	[redacted]	27	30
39 OPERATING EXPENSE ACCT NO. 903	OX903	43,062	[redacted]	65,999	76,970	[redacted]	108,136	[redacted]	100,831	187,912
40 OPERATING EXPENSE ACCT NO. 904	OX904	671	[redacted]	1,176	10,076	[redacted]	16,006	[redacted]	2,611	14,101
SCHEDULE G-4 INTERNALLY DEVELOPED (CON'T)										
1 OPERATING EXPENSE ACCT NO. 905	OX905	229	[redacted]	351	410	[redacted]	576	[redacted]	537	1,000
2 OPERATING EXPENSE ACCT NO. 907	OX907	179	[redacted]	656	4,939	[redacted]	9,359	[redacted]	818	7,712
3 OPERATING EXPENSE ACCT NO. 908	OX908	620	[redacted]	2,274	17,125	[redacted]	32,449	[redacted]	2,838	26,738
4 OPERATING EXPENSE ACCT NO. 909	OX909	3	[redacted]	9	71	[redacted]	135	[redacted]	12	111
5 OPERATING EXPENSE ACCT NO. 910	OX910	2	[redacted]	6	42	[redacted]	80	[redacted]	7	66
6 OPERATING EXPENSE ACCT NO. 911	OX911	0	[redacted]	0	2	[redacted]	3	[redacted]	0	2

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	LIGHT & POWER TOU SEC (17)	LIGHT & POWER TOU PRI (18)	LIGHT & POWER TOU TOTAL (19)	LARGE INDUSTRIAL LARGE LIGHT & POWER PRI (20)	LARGE INDUSTRIAL LARGE LIGHT & POWER 69 KV (21)	LARGE INDUSTRIAL LARGE LIGHT & POWER TOTAL (22)	LARGE INDUSTRIAL PULP & PAPER MILL INDUSTRIAL (23)	LARGE INDUSTRIAL LP PRIMARY CURTAILABLE (24)	LARGE INDUSTRIAL TOTAL (25)
7 OPERATING EXPENSE ACCT NO. 912	OX912	30	[redacted]	108	817	[redacted]	1,548	[redacted]	135	1,276
8 OPERATING EXPENSE ACCT NO. 913	OX913	(4)	[redacted]	(15)	(110)	[redacted]	(209)	[redacted]	(18)	(172)
9 OPERATING EXPENSE ACCT NO. 916	OX916	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
10 OPERATING EXPENSE ACCT NO. 920	OX920	18,938	[redacted]	38,716	222,793	[redacted]	353,195	[redacted]	56,583	272,828
11 OPERATING EXPENSE ACCT NO. 921	OX921	1,379	[redacted]	2,819	16,221	[redacted]	25,716	[redacted]	4,120	19,864
12 OPERATING EXPENSE ACCT NO. 922	OX922	(2,033)	[redacted]	(4,156)	(23,918)	[redacted]	(37,918)	[redacted]	(6,075)	(29,290)
13 OPERATING EXPENSE ACCT NO. 923	OX923	9,735	[redacted]	19,901	114,523	[redacted]	181,554	[redacted]	29,086	140,243
14 1/8 O&M LESS FUEL & PURCHASED PWR	OMX	26,601	[redacted]	57,805	387,520	[redacted]	644,779	[redacted]	89,933	491,828
15 DEPRECIATION EXPENSE	DEPREXP	82,172	[redacted]	177,345	1,482,797	[redacted]	2,213,157	[redacted]	281,746	1,482,202
16 AD VALOREM TAXES	PROPTAX	23,473	[redacted]	51,620	437,047	[redacted]	662,051	[redacted]	82,576	450,881
17 LABOR ACCOUNTS 501 THRU 507	LAB501_507	4,301	[redacted]	13,523	141,625	[redacted]	235,740	[redacted]	19,793	175,486
18 LABOR ACCOUNTS 511 THRU 514	LAB511_514	4,294	[redacted]	15,335	118,725	[redacted]	220,217	[redacted]	19,262	178,391
19 LABOR ACCOUNTS 547 THRU 550	LAB547_550	70	[redacted]	210	2,445	[redacted]	3,935	[redacted]	326	2,843
20 LABOR ACCOUNTS 552 THRU 554	LAB552_554	39	[redacted]	117	1,364	[redacted]	2,195	[redacted]	182	1,585
21 LABOR ACCOUNTS 561 THRU 567	LAB561_567	526	[redacted]	1,446	14,671	[redacted]	25,660	[redacted]	2,771	20,152
22 LABOR ACCOUNTS 569 THRU 573	LAB569_573	836	[redacted]	2,299	23,320	[redacted]	40,788	[redacted]	4,405	32,032
23 LABOR ACCOUNTS 581 THRU 589	LAB581_589	9,342	[redacted]	14,912	69,428	[redacted]	71,104	[redacted]	21,723	23,403
24 LABOR ACCOUNTS 591 THRU 598	LAB591_598	5,771	[redacted]	8,907	40,448	[redacted]	40,658	[redacted]	12,082	12,293
25 LABOR ACCOUNTS 902 THRU 905	LAB902_905	20,693	[redacted]	31,699	36,981	[redacted]	51,928	[redacted]	48,431	90,245
26 LABOR ACCOUNTS 908 THRU 910	LAB908_910	611	[redacted]	2,241	16,078	[redacted]	31,980	[redacted]	2,797	26,352
27 LABOR ACCOUNTS 912 THRU 916	LAB912_916	0	[redacted]	1	4	[redacted]	7	[redacted]	1	6
28 PAYROLL EXCLUDING A&G	LABORX	53,923	[redacted]	110,627	639,832	[redacted]	1,016,040	[redacted]	161,836	785,221
29 RETAIL PAYROLL EXCLUDING A&G	LABORXR	53,923	[redacted]	110,627	639,832	[redacted]	1,016,040	[redacted]	161,836	785,221
30 TOTAL PAYROLL	LABORT	65,102	[redacted]	133,090	765,872	[redacted]	1,214,144	[redacted]	194,510	937,875
31 ACCT 903 EXCL BILLING	OX903X	0	[redacted]	-	0	[redacted]	-	[redacted]	0	-
32 ACCT 903 BILLING	OX903B	43,082	[redacted]	65,999	78,970	[redacted]	108,136	[redacted]	100,831	187,912
33 PRODUCTION LABOR	LABPROD	12,574	[redacted]	41,564	363,852	[redacted]	672,316	[redacted]	57,313	516,511
34 TRANSMISSION LABOR	LABTRAN	2,500	[redacted]	6,878	69,767	[redacted]	122,025	[redacted]	13,179	95,830
35 DISTR LABOR EXCL METERING	LABDIST	15,984	[redacted]	24,964	116,286	[redacted]	116,633	[redacted]	34,554	34,903
36 CUST SERVICE LABOR EXCL METER & BILLING	LABCUSSV	22,778	[redacted]	36,851	64,360	[redacted]	102,815	[redacted]	55,360	134,861
37 METERING LABOR	LABMETER	86	[redacted]	370	568	[redacted]	2,251	[redacted]	1,429	3,116
38 BILLING LABOR	LABBILL	0	[redacted]	-	0	[redacted]	-	[redacted]	0	-

SCHEDULE G-4
INTERNALLY DEVELOPED (CON'T)

	ALLOC	SEC (17)	PRI (18)	TOTAL (19)	PRI (20)	69 KV (21)	TOTAL (22)	INDUSTRIAL (23)	CURTAILABLE (24)	TOTAL (25)
1 SALES REVENUE	REVSALES	248,498	[redacted]	435,558	3,731,299	[redacted]	5,927,210	[redacted]	966,899	5,221,554
2 0.5*PRODPLT + 0.95*TDPLT	PTDPLTW	2,392,613	[redacted]	4,948,486	38,900,027	[redacted]	57,590,720	[redacted]	8,031,574	38,187,264
3 REV DEF @ CLAIMED * FACTORING	FACTC	0	[redacted]	-	0	[redacted]	-	[redacted]	0	-
4 REV DEF @ PROPOSED * FACTORING	FACTP	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
5 COS @ CLAIMED * AR REV REL TAX	REVFACC1	1.00000	[redacted]	2	1.00000	[redacted]	2	[redacted]	1.00000	2
6 COS @ CLAIMED * LA REV RELA TAX	REVFACC2	0.00000	[redacted]	-	0.00000	[redacted]	-	[redacted]	0.00000	-
7 COS @ CLAIMED * TX REV REL TAX	REVFACC3	0.00000	[redacted]	-	0.00000	[redacted]	-	[redacted]	0.00000	-
8 PROPOSED REV * AR REV REL TX	REVFACP1	1.00000	[redacted]	2	1.00000	[redacted]	2	[redacted]	1.00000	2
9 PROPOSED REV * LA REV REL TAX	REVFACP2	0.00000	[redacted]	-	0.00000	[redacted]	-	[redacted]	0.00000	-
10 PROPOSED REV * TX REV REL TAX	REVFACP3	0.00000	[redacted]	-	0.00000	[redacted]	-	[redacted]	0.00000	-
11 FUEL - RETAIL	FUELR	5,586	[redacted]	20,197	151,467	[redacted]	284,525	[redacted]	24,995	232,539
12 FUEL - WHOLESALE	FUELW	0	[redacted]	-	0	[redacted]	-	[redacted]	0	-
13 SALES REVENUE - RETAIL	REVSALESR	248,498	[redacted]	435,558	3,731,299	[redacted]	5,927,210	[redacted]	966,899	5,221,554
14 SALES REVENUE - WHOLESALE	REVSALESW	0	[redacted]	-	0	[redacted]	-	[redacted]	0	-
15 SALES REVENUE - ARKANSAS	REVSALEAR	248,498	[redacted]	435,558	3,731,299	[redacted]	5,927,210	[redacted]	966,899	5,221,554
16 SALES REVENUE - LOUISIANA	REVSALELA	0	[redacted]	-	0	[redacted]	-	[redacted]	0	-
17 SALES REVENUE - TEXAS	REVSALETX	0	[redacted]	-	0	[redacted]	-	[redacted]	0	-
18 PRODUCTION PLANT - TEXAS	PRODPLTTX	0	[redacted]	-	0	[redacted]	-	[redacted]	0	-
19 DISTRIBUTION PLANT - LOUISIANA	DISTPLTLA	0	[redacted]	-	0	[redacted]	-	[redacted]	0	-
20 RETAIL REVENUE LA	RREVLA	0	[redacted]	-	0	[redacted]	-	[redacted]	0	-
21 TAXABLE INCOME LA	TAXINCLA	0	[redacted]	-	0	[redacted]	-	[redacted]	0	-
22 TAXABLE INCOME AR	TAXINCAR	(113,535)	[redacted]	(346,714)	(1,910,650)	[redacted]	(2,875,236)	[redacted]	(229,677)	(1,171,627)

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	LIGHT & POWER TOU			LARGE INDUSTRIAL					
					LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
		SEC	PRI	TOTAL	PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE	TOTAL
		(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)
23 PLANT LA	PLANTLA	0	[redacted]	-	0	[redacted]	-	[redacted]	0	-
24 PLANT AR	PLANTAR	2,985,655	[redacted]	6,566,148	55,592,990	[redacted]	84,213,833	[redacted]	10.503 782	57,352,683
25 DEMAND PROD WHOLESALE	DPRODWH	0	[redacted]	-	0	[redacted]	-	[redacted]	0	-
26 DEMAND PROD ARKANSAS	DPRODAR	657,729	[redacted]	1,964,778	22,929,217	[redacted]	36,897,101	[redacted]	3,055,567	26,653,946
27 DEMAND PROD LOUISIANA	DPRODLA	0	[redacted]	-	0	[redacted]	-	[redacted]	0	-
28 DEMAND PROD TEXAS	DPRODTX	0	[redacted]	-	0	[redacted]	-	[redacted]	0	-
29 DEMAND TRAN WHOLESALE	DTRANWH	0	[redacted]	-	0	[redacted]	-	[redacted]	0	-
30 DEMAND TRAN ARKANSAS	DTRANAR	577,381	[redacted]	1,588,415	16,112,125	[redacted]	28,180,927	[redacted]	3,043,648	22,131,364
31 DEMAND TRAN LOUISIANA	DTRANLA	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
32 DEMAND TRAN TEXAS	DTRANTX	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
33 DEMAND DIST WHOLESALE	DDISTWH	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
34 DEMAND DIST ARKANSAS	DDISTAR	1,592,335	[redacted]	2,575,078	12,702,919	[redacted]	12,752,112	[redacted]	3,784,192	3,833,506
35 DEMAND DIST LOUISIANA	DDISTLA	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
36 DEMAND DIST TEXAS	DDISTTX	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
37 DEMAND GENERAL WHOLESALE	DGENLWH	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
38 DEMAND GENERAL ARKANSAS	DGENLAR	80,453	[redacted]	265,948	2,488,062	[redacted]	4 301,801	[redacted]	366,718	3,304,886
39 DEMAND GENERAL LOUISIANA	DGENLLA	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
40 DEMAND GENERAL TEXAS	DGENLTX	0	[redacted]	0	0	[redacted]	0	[redacted]	0	0
SCHEDULE G-4			[redacted]			[redacted]		[redacted]		
INTERNALLY DEVELOPED (CON'T)			[redacted]			[redacted]		[redacted]		
1 PRODUCTION PLANT - TEXAS RETAIL	PRODPLTT	0	[redacted]	-	0	[redacted]	-	[redacted]	0	-
2 LABOR 902 & 903	LAB902_903	20,656	[redacted]	31,642	36,895	[redacted]	51,835	[redacted]	43,344	90,083
3 SALES REVENUE - AR RETAIL	RVSALEARR	248,498	[redacted]	435,558	3,731,299	[redacted]	5,927,210	[redacted]	966,899	5,221,554
4 SALES REVENUE - LA RETAIL	RVSALELAR	0	[redacted]	-	0	[redacted]	-	[redacted]	0	-
5 SALES REVENUE - TX RETAIL	RVSALETXR	0	[redacted]	-	0	[redacted]	-	[redacted]	0	-
6 DIST PLANT BEFORE CONTRA ADJ	DISTPLTX	1,592,335	[redacted]	2,575,078	12 702,919	[redacted]	12,752,112	[redacted]	3,784 192	3,833,506
7 STATE INCOME TAX	SIT	(3,628)	[redacted]	(11,002)	(61,222)	[redacted]	(92,146)	[redacted]	(7 444)	(38,249)
8 RETAIL PRODUCTION PLANT	PRODPLTR	667 127	[redacted]	1,992,851	23 256,828	[redacted]	37,424,283	[redacted]	3,099,245	27,034,775
9 TOTAL kWh AT GEN - ARKANSAS	KWHAR	6 761,775	[redacted]	24,440,791	183,290 750	[redacted]	344,305,546	[redacted]	30,246,977	281,396,933
10 TOTAL kWh AT GEN - LOUISIANA	KWHLA	0	[redacted]	-	0	[redacted]	-	[redacted]	0	-
11 TOTAL kWh AT GEN - TEXAS	KWHTX	0	[redacted]	-	0	[redacted]	-	[redacted]	0	-
12 INTANGIBLE PLANT	INTPLT	70,854	[redacted]	147,285	1,046,402	[redacted]	1,562,930	[redacted]	214 712	1,044,730
13 DEMPROD RETAIL	DEMRTAIL	0 0011	[redacted]	0.0033	0 0382	[redacted]	0.0614	[redacted]	0 0051	0.0444
14 FIT TEMPORARY DIFFERENCES	FITTEMP	(20,570)	[redacted]	(47,820)	(398,846)	[redacted]	(624,024)	[redacted]	(74,202)	(440,680)
15 Total Depr Expense	DEPEXP	82,172	[redacted]	177,345	1 482,797	[redacted]	2,213 157	[redacted]	281,746	1,482,202
16 AVAILABLE	AVAIL	0	[redacted]	-	0	[redacted]	-	[redacted]	0	-
17 Composite Tax Rate (FIT and AR State)	COMPTR	26.1350%	[redacted]	26.1350%	26.1350%	[redacted]	26.1350%	[redacted]	26.1350%	26.1350%
18 Combined Tax Gross Up (FIT and AR State)	TAX GU	35.3821%	[redacted]	35.3821%	35.3821%	[redacted]	35.3821%	[redacted]	35.3821%	35.3821%
19 CLAIMED FACTORING	RFACT	0.0460%	[redacted]	0.0460%	0.0090%	[redacted]	0.0090%	[redacted]	0.0090%	0.0090%
20 Gross Revenue Conversion Factor	REVCONV	1.354444	[redacted]	1.354444	1.353943	[redacted]	1.353943	[redacted]	1.353943	1.353943
21 AVAILABLE	AVAIL	0	[redacted]	-	0	[redacted]	-	[redacted]	0	-
SCHEDULE G-4			[redacted]			[redacted]		[redacted]		
RATIO TABLE			[redacted]			[redacted]		[redacted]		
CAPACITY RELATED			[redacted]			[redacted]		[redacted]		
1 PRODUCTION ALLOCATOR	DEMPROD	0.00109	[redacted]	0.00327	0.03817	[redacted]	0.06143	[redacted]	0.00509	0.04437
2			[redacted]			[redacted]		[redacted]		
3 TRANSMISSION FUNCTION	DEMTRANS	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
4 D. A. ACCT 360 - LAND (MDD)	DEM360DA	0.00375	[redacted]	0.00694	0.04162	[redacted]	0.04162	[redacted]	0.01227	0.01227
5 D. A. ACCT 361 - STRUCTURES & IMPROVE	DEM361DA	0.00375	[redacted]	0.00694	0.04162	[redacted]	0.04162	[redacted]	0.01227	0.01227
6 D. A. ACCT 362 - STATION EQUIPMENT	DEM362DA	0.00375	[redacted]	0.00694	0.04162	[redacted]	0.04162	[redacted]	0.01227	0.01227
7 D. A. ACCT 364 - PRI-POLES, TOWERS & FIX	DEM364DAP	0.00375	[redacted]	0.00694	0.04162	[redacted]	0.04162	[redacted]	0.01227	0.01227
8 D. A. ACCT 364 - SEC POLES, TOWERS & FIX	DEM364DAS	0.00446	[redacted]	0.00446	-	[redacted]	-	[redacted]	-	-
9 D. A. ACCT 365 - PRI - OVRHD COND & DEVICES	DEM365DAP	0.00375	[redacted]	0.00694	0.04162	[redacted]	0.04162	[redacted]	0.01227	0.01227
10 D. A. ACCT 365 - SEC - OVRHD COND & DEVICES	DEM365DAS	0.00446	[redacted]	0.00446	-	[redacted]	-	[redacted]	-	-
11 D. A. ACCT 366 - PRI - UNDERGROUND CONDUIT	DEM366DAP	0.00375	[redacted]	0.00694	0.04162	[redacted]	0.04162	[redacted]	0.01227	0.01227
12 D. A. ACCT 366 - SEC - UNDERGROUND CONDUIT	DEM366DAS	0.00446	[redacted]	0.00446	-	[redacted]	-	[redacted]	-	-
13 D. A. ACCT 367 - PRI - UNDGRD COND & DEVICE	DEM367DAP	0.00375	[redacted]	0.00694	0.04162	[redacted]	0.04162	[redacted]	0.01227	0.01227

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
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Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross refereneces to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

					LARGE INDUSTRIAL					
	ALLOC	LIGHT & POWER TOU			LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
		SEC (17)	PRI (18)	TOTAL (19)	PRI (20)	69 KV (21)	TOTAL (22)	INDUSTRIAL (23)	CURTAILABLE (24)	TOTAL (25)
14 D. A. ACCT 367 - SEC - UNDGRD COND & DEVICE	DEM367DAS	0.00446	[redacted]	0.00446	-	[redacted]	-	[redacted]	-	-
15 D. A. ACCT 368 - LINE TRANSORMERS	DEM368DA	0.00375	[redacted]	0.00694	0.04162	[redacted]	0.04162	[redacted]	0.01227	0.01227
16 ANNUAL BILLING DEMAND	DEM99	0.00480	[redacted]	0.00956	0.05062	[redacted]	0.08918	[redacted]	0.02512	0.09354
17 SPP DEMAND	SPPDEMAND	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
18 AVAILABLE-SUBSTATIONS	USERSUB	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
19 AVAILABLE-DIR ASSIGN SUBS	USERDASUB	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
20 AVAILABLE-PRI OVHD	USEROVHD	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
21 AVAILABLE-SECONDARY	USERSEC	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
22			[redacted]			[redacted]		[redacted]		
23			[redacted]			[redacted]		[redacted]		
24			[redacted]			[redacted]		[redacted]		
25 COMMODITY RELATED			[redacted]			[redacted]		[redacted]		
26 ------------------------------------			[redacted]			[redacted]		[redacted]		
27 FUEL ALLOCATION	FUEL	0.00168	[redacted]	0.00504	0.04448	[redacted]	0.08458	[redacted]	0.00741	0.06973
28 KWH SALES AT GENERATOR	ENERGY	0.00164	[redacted]	0.00592	0.04437	[redacted]	0.08335	[redacted]	0.00732	0.06812
29 SALES OF ELECTRICITY - PRESENT FUEL	REVFUEL	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
30 KWH SALES AT METER	ENERGY99	0.00162	[redacted]	0.00597	0.04513	[redacted]	0.08551	[redacted]	0.00745	0.07044
31 MINE CLOSING	MINECLOSE	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
32 MINE CLOSING NFIRM RETAIL	MINECLOSEN	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
33 NON FIRM FUEL PRESENT FUEL	NFREVFUEL	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
34 FUEL ADJUSTMENT	FUELADJ	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
35 NON FIRM PROPOSED FUEL RETAIL	NFPROPFUEL	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
36 PROPOSED FUEL REVENUE	PROPFUEL	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
SCHEDULE G-4			[redacted]			[redacted]		[redacted]		
CUSTOMER RELATED			[redacted]			[redacted]		[redacted]		
------------------------------------			[redacted]			[redacted]		[redacted]		
1 ANNUAL AVERAGE CUSTOMERS	CUST99	0.00001	[redacted]	0.00002	0.00001	[redacted]	0.00002	[redacted]	0.00003	0.00004
2 YEAR END NUMBER OF CUSTOMERS	CUST	0.00001	[redacted]	0.00002	0.00001	[redacted]	0.00002	[redacted]	0.00003	0.00004
3 WEIGHTED SERVICES	CUST369	0.00005	[redacted]	0.00007	0.00005	[redacted]	0.00005	[redacted]	0.00012	0.00012
4 WEIGHTED METERS	CUST370	0.00012	[redacted]	0.00057	0.00069	[redacted]	0.00354	[redacted]	0.00223	0.00489
5 ASSIGNED CUSTOMER INSTALLATIONS	CUST371L	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
6 LIGHTING ASSIGNMENTS	CUST373	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
7 WEIGHTED METERS	CUST902	0.00002	[redacted]	0.00003	0.00002	[redacted]	0.00002	[redacted]	0.00006	0.00006
8 CUSTOMER ACCOUNTING	CUST903	0.01137	[redacted]	0.01742	0.02032	[redacted]	0.02855	[redacted]	0.02662	0.04961
9 CUSTOMER INFO EXP ALLOC	CUSTINFO	0.00001	[redacted]	0.00002	0.00001	[redacted]	0.00002	[redacted]	0.00003	0.00004
10 CUSTOMER SERVICE EXP ALLOC	CUSTSRVC	0.00001	[redacted]	0.00002	0.00001	[redacted]	0.00002	[redacted]	0.00003	0.00004
11 ACTIVE CUSTOMER DEPOSITS	CUSTOEPA	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
12 CUSTOMERS IN AR & LA	CUSTARLA	0.00001	[redacted]	0.00002	0.00001	[redacted]	0.00002	[redacted]	0.00003	0.00004
13 RETAIL CUSTOMERS	CUSTRET	0.00001	[redacted]	0.00002	0.00001	[redacted]	0.00002	[redacted]	0.00003	0.00004
14 AVAILABLE-SERVICE DROP	CUSER1	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
15 AVAILABLE-SERVICE DROP	CUSER2	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
16 AVAILABLE-METERS	CUSER3	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
17 AVAILABLE-METERS	CUSER4	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
18 AVAILABLE-CUSTOMER SERVICES	CUSER5	0.00002	[redacted]	0.00003	0.00002	[redacted]	0.00002	[redacted]	0.00006	0.00006
19 AVAILABLE-CUSTOMER SERVICES	CUSER6	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
20 CUSTOMER ENERGY SPLIT 907-916	CUSER7	0.00082	[redacted]	0.00300	0.02257	[redacted]	0.04276	[redacted]	0.00374	0.03524
21 AVAILABLE-CUSTOMER BILLING	CUSER8	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
22 AVAILABLE-CUSTOMER BILLING	CUSER9	0.00018	[redacted]	0.00018	0.02880	[redacted]	0.04536	[redacted]	-	0.03807
23 AVAILABLE-CUSTOMER LTG AND MISC REV	CUSER10	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
24 AVAILABLE-CUSTOMER LTG AND MISC REV			[redacted]			[redacted]		[redacted]		
25 AVAILABLE-CUSTOMER OTHER			[redacted]			[redacted]		[redacted]		
REVENUE RELATED STRINGS			[redacted]			[redacted]		[redacted]		
------------------------------------			[redacted]			[redacted]		[redacted]		
29 SALES OF ELECTRICITY-BASE	R40B	0.00192	[redacted]	0.00337	0.02888	[redacted]	0.04588	[redacted]	0.00748	0.04042
30 GROSS RECEIPTS FACTOR	RGR	0.06667	[redacted]	0.13333	0.06667	[redacted]	0.13333	[redacted]	0.06667	0.13333
31 CLAIMED RATE OF RETURN	ROR	1.00000	[redacted]	1.00000	1.00000	[redacted]	1.00000	[redacted]	1.00000	1.00000
32 CLAIMED FACTORING	RFACT	0.14353	[redacted]	0.14353	0.02808	[redacted]	0.02808	[redacted]	0.02808	0.02808
33 PROPOSED REVENUES	PREV	0.00272	[redacted]	0.00477	0.03010	[redacted]	0.04884	[redacted]	0.00900	0.03967

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC				LARGE INDUSTRIAL					
		LIGHT & POWER TOU			LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
		SEC	PRI	TOTAL	PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE	TOTAL
		(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)
34 FEDERAL INCOME TAX RATE		1.00000	[redacted]	1.00000	1.00000	[redacted]	1.00000	[redacted]	1.00000	1.00000
35 LOUISIANA APPORTIONMENT FACTOR		1.00000	[redacted]	1.00000	1.00000	[redacted]	1.00000	[redacted]	1.00000	1.00000
36 LOUISIANA INCOME TAX RATE		1.00000	[redacted]	1.00000	1.00000	[redacted]	1.00000	[redacted]	1.00000	1.00000
37 ARKANSAS APPORTIONMENT FACTOR		1.00000	[redacted]	1.00000	1.00000	[redacted]	1.00000	[redacted]	1.00000	1.00000
38 ARKANSAS INCOME TAX RATE		1.00000	[redacted]	1.00000	1.00000	[redacted]	1.00000	[redacted]	1.00000	1.00000
SCHEDULE G-4 INTERNALLY DEVELOPED			[redacted]			[redacted]		[redacted]		
1 PRODUCTION PLANT	PRODPLT	0.00109	[redacted]	0.00327	0.03817	[redacted]	0.06143	[redacted]	0.00509	0.04437
2 PLANT ACCOUNT 352	PLT352	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
3 PLANT ACCOUNT 353	PLT353	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
4 PLANT ACCOUNTS 352 & 353	TRANSUB	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
5 PLANT ACCOUNTS 354, 355 & 356	TRANOHLN	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
6 PLANT ACCOUNT 357	TRANUGLN	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
7 TRANSMISSION PLANT	TRANPLT	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
8 PROD. & TRANS. PLANT	PTPLT	0.00122	[redacted]	0.00351	0.03858	[redacted]	0.06429	[redacted]	0.00602	0.04818
9 PLANT ACCOUNT 361	PLT361	0.00375	[redacted]	0.00694	0.04162	[redacted]	0.04162	[redacted]	0.01227	0.01227
10 PLANT ACCOUNT 362	PLT362	0.00375	[redacted]	0.00694	0.04162	[redacted]	0.04162	[redacted]	0.01227	0.01227
11 PLANT ACCOUNT 368	PLT368	0.00375	[redacted]	0.00694	0.04162	[redacted]	0.04162	[redacted]	0.01227	0.01227
12 PLANT ACCOUNT 370	PLT370	0.00012	[redacted]	0.00057	0.00089	[redacted]	0.00354	[redacted]	0.00223	0.00489
13 PLANT ACCOUNT 371	PLT371	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
14 PLANT ACCOUNT 373	PLT373	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
15 PLANT ACCOUNT 361 & 362	DISTSUB	0.00375	[redacted]	0.00694	0.04162	[redacted]	0.04162	[redacted]	0.01227	0.01227
16 PLANT ACCOUNT 364 & 365	DISTOHLN	0.00398	[redacted]	0.00612	0.02787	[redacted]	0.02787	[redacted]	0.00822	0.00822
17 PLANT ACCOUNT 366 & 367	DISTUGLN	0.00412	[redacted]	0.00563	0.01965	[redacted]	0.01965	[redacted]	0.00579	0.00579
18 DISTRIBUTION PLANT	DISTPLT	0.00345	[redacted]	0.00558	0.02754	[redacted]	0.02765	[redacted]	0.00820	0.00831
19 TRANS. & DISTR. PLANT	TDPLT	0.00249	[redacted]	0.00477	0.03303	[redacted]	0.04694	[redacted]	0.00783	0.02978
20 PROD., TRANS., & DISTR. PLANT	PTDPLT	0.00191	[redacted]	0.00415	0.03515	[redacted]	0.05290	[redacted]	0.00670	0.03579
21 GENERAL PLANT EXCL ADJUSTMENTS	GENPLTX	0.00132	[redacted]	0.00435	0.04070	[redacted]	0.07038	[redacted]	0.00600	0.05407
22 GENERAL PLANT	GENPLT	0.00132	[redacted]	0.00435	0.04070	[redacted]	0.07038	[redacted]	0.00600	0.05407
23 TOTAL ELECTRIC PLANT IN SERVICE	PLANT	0.00190	[redacted]	0.00417	0.03534	[redacted]	0.05354	[redacted]	0.00668	0.03646
24 NET PLANT IN SERVICE	NETPLT	0.00202	[redacted]	0.00429	0.03488	[redacted]	0.05225	[redacted]	0.00691	0.03517
25 RATE BASE	RBX	0.00203	[redacted]	0.00435	0.03492	[redacted]	0.05258	[redacted]	0.00695	0.03567
26 OPERATING EXPENSE ACCT NO. 500	OX500	0.00119	[redacted]	0.00375	0.03930	[redacted]	0.06542	[redacted]	0.00549	0.04870
27 OPERATING EXPENSE ACCT NO. 501	OX501	0.00164	[redacted]	0.00592	0.04437	[redacted]	0.08335	[redacted]	0.00732	0.06812
28 OPERATING EXPENSE ACCT NO. 502	OX502	0.00109	[redacted]	0.00327	0.03817	[redacted]	0.06143	[redacted]	0.00509	0.04437
29 OPERATING EXPENSE ACCT NO. 505	OX505	0.00109	[redacted]	0.00327	0.03817	[redacted]	0.06143	[redacted]	0.00509	0.04437
30 OPERATING EXPENSE ACCT NO. 506	OX506	0.00109	[redacted]	0.00327	0.03817	[redacted]	0.06143	[redacted]	0.00509	0.04437
31 MAINTENANCE EXPENSE ACCT NO. 510	MX510	0.00158	[redacted]	0.00565	0.04375	[redacted]	0.08115	[redacted]	0.00710	0.06574
32 MAINTENANCE EXPENSE ACCT NO. 511	MX511	0.00109	[redacted]	0.00327	0.03817	[redacted]	0.06143	[redacted]	0.00509	0.04437
33 MAINTENANCE EXPENSE ACCT NO. 512	MX512	0.00164	[redacted]	0.00592	0.04437	[redacted]	0.08335	[redacted]	0.00732	0.06812
34 MAINTENANCE EXPENSE ACCT NO. 513	MX513	0.00164	[redacted]	0.00592	0.04437	[redacted]	0.08335	[redacted]	0.00732	0.06812
35 MAINTENANCE EXPENSE ACCT NO. 514	MX514	0.00109	[redacted]	0.00327	0.03817	[redacted]	0.06143	[redacted]	0.00509	0.04437
36 OPERATING EXPENSE ACCT NO. 546	OX546	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
37 OPERATING EXPENSE ACCT NO. 548	OX548	0.00109	[redacted]	0.00327	0.03817	[redacted]	0.06143	[redacted]	0.00509	0.04437
38 OPERATING EXPENSE ACCT NO. 549	OX549	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
39 MAINTENANCE EXPENSE ACCT NO. 551	MX551	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
40 MAINTENANCE EXPENSE ACCT NO. 552	MX552	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
SCHEDULE G-4 INTERNALLY DEVELOPED (CON'T)			[redacted]			[redacted]		[redacted]		
1 MAINTENANCE EXPENSE ACCT NO. 553	MX553	0.00109	[redacted]	0.00327	0.03817	[redacted]	0.06143	[redacted]	0.00509	0.04437
2 MAINTENANCE EXPENSE ACCT NO. 554	MX554	0.00109	[redacted]	0.00327	0.03817	[redacted]	0.06143	[redacted]	0.00509	0.04437
3 OPERATING EXPENSE ACCT NO. 556	OX556	0.00109	[redacted]	0.00327	0.03817	[redacted]	0.06143	[redacted]	0.00509	0.04437
4 OPERATING EXPENSE ACCT NO. 557	OX557	0.00109	[redacted]	0.00327	0.03817	[redacted]	0.06143	[redacted]	0.00509	0.04437
5 OPERATING EXPENSE ACCT NO. 560	OX560	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
6 OPERATING EXPENSE ACCT NO. 561	OX561	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
7 OPERATING EXPENSE ACCT NO. 562	OX562	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross refereneces to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

					LARGE INDUSTRIAL					
	ALLOC	LIGHT & POWER TOU			LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
		SEC	PRI	TOTAL	PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE	TOTAL
		(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)
8 OPERATING EXPENSE ACCT NO. 563	OX563	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
9 OPERATING EXPENSE ACCT NO. 564	OX564	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
10 OPERATING EXPENSE ACCT NO. 565	OX565	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
11 OPERATING EXPENSE ACCT NO. 566	OX566	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
12 MAINTENANCE EXPENSE ACCT NO. 568	MX568	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
13 MAINTENANCE EXPENSE ACCT NO. 569	MX569	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
14 MAINTENANCE EXPENSE ACCT NO. 570	MX570	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
15 MAINTENANCE EXPENSE ACCT NO. 571	MX571	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
16 MAINTENANCE EXPENSE ACCT NO. 572	MX572	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
17 MAINTENANCE EXPENSE ACCT NO. 573	MX573	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
18 OPERATING EXPENSE ACCT NO. 580	OX580	0.00290	[redacted]	0.00463	0.02154	[redacted]	0.02206	[redacted]	0.00674	0.00726
19 OPERATING EXPENSE ACCT NO. 581	OX581	0.00345	[redacted]	0.00558	0.02754	[redacted]	0.02765	[redacted]	0.00820	0.00831
20 OPERATING EXPENSE ACCT NO. 582	OX582	0.00375	[redacted]	0.00694	0.04162	[redacted]	0.04162	[redacted]	0.01227	0.01227
21 OPERATING EXPENSE ACCT NO. 583	OX583	0.00398	[redacted]	0.00612	0.02787	[redacted]	0.02787	[redacted]	0.00622	0.00822
22 OPERATING EXPENSE ACCT NO. 584	OX584	0.00412	[redacted]	0.00563	0.01965	[redacted]	0.01965	[redacted]	0.00579	0.00579
23 OPERATING EXPENSE ACCT NO. 585	OX585	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
24 OPERATING EXPENSE ACCT NO. 586	OX586	0.00012	[redacted]	0.00057	0.00089	[redacted]	0.00354	[redacted]	0.00223	0.00489
25 OPERATING EXPENSE ACCT NO. 587	OX587	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
26 OPERATING EXPENSE ACCT NO. 588	OX588	0.00345	[redacted]	0.00558	0.02754	[redacted]	0.02765	[redacted]	0.00820	0.00831
27 OPERATING EXPENSE ACCT NO. 589	OX589	0.00345	[redacted]	0.00558	0.02754	[redacted]	0.02765	[redacted]	0.00820	0.00831
28 MAINTENANCE EXPENSE ACCT NO. 590	MX590	0.00361	[redacted]	0.00558	0.02532	[redacted]	0.02546	[redacted]	0.00756	0.00770
29 MAINTENANCE EXPENSE ACCT NO. 591	MX591	0.00375	[redacted]	0.00694	0.04162	[redacted]	0.04162	[redacted]	0.01227	0.01227
30 MAINTENANCE EXPENSE ACCT NO. 592	MX592	0.00375	[redacted]	0.00694	0.04162	[redacted]	0.04162	[redacted]	0.01227	0.01227
31 MAINTENANCE EXPENSE ACCT NO. 593	MX593	0.00398	[redacted]	0.00612	0.02787	[redacted]	0.02787	[redacted]	0.00822	0.00822
32 MAINTENANCE EXPENSE ACCT NO. 594	MX594	0.00412	[redacted]	0.00563	0.01965	[redacted]	0.01965	[redacted]	0.00579	0.00579
33 MAINTENANCE EXPENSE ACCT NO. 595	MX595	0.00375	[redacted]	0.00694	0.04162	[redacted]	0.04162	[redacted]	0.01227	0.01227
34 MAINTENANCE EXPENSE ACCT NO. 596	MX596	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
35 MAINTENANCE EXPENSE ACCT NO. 597	MX597	0.00012	[redacted]	0.00057	0.00089	[redacted]	0.00354	[redacted]	0.00223	0.00489
36 MAINTENANCE EXPENSE ACCT NO. 598	MX598	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
37 OPERATING EXPENSE ACCT NO. 901	OX901	0.00906	[redacted]	0.01388	0.01619	[redacted]	0.02275	[redacted]	0.02121	0.03953
38 OPERATING EXPENSE ACCT NO. 902	OX902	0.00002	[redacted]	0.00003	0.00002	[redacted]	0.00002	[redacted]	0.00006	0.00006
39 OPERATING EXPENSE ACCT NO. 903	OX903	0.01060	[redacted]	0.01623	0.01893	[redacted]	0.02660	[redacted]	0.02480	0.04622
40 OPERATING EXPENSE ACCT NO. 904	OX904	0.00192	[redacted]	0.00337	0.02888	[redacted]	0.04588	[redacted]	0.00748	0.04042
SCHEDULE G-4										
INTERNALLY DEVELOPED (CON'T)										
1 OPERATING EXPENSE ACCT NO. 905	OX905	0.00906	[redacted]	0.01388	0.01619	[redacted]	0.02275	[redacted]	0.02121	0.03953
2 OPERATING EXPENSE ACCT NO. 907	OX907	0.00082	[redacted]	0.00300	0.02257	[redacted]	0.04276	[redacted]	0.00374	0.03524
3 OPERATING EXPENSE ACCT NO. 908	OX908	0.00082	[redacted]	0.00300	0.02257	[redacted]	0.04276	[redacted]	0.00374	0.03524
4 OPERATING EXPENSE ACCT NO. 909	OX909	0.00082	[redacted]	0.00300	0.02257	[redacted]	0.04276	[redacted]	0.00374	0.03524
5 OPERATING EXPENSE ACCT NO. 910	OX910	0.00082	[redacted]	0.00300	0.02257	[redacted]	0.04276	[redacted]	0.00374	0.03524
6 OPERATING EXPENSE ACCT NO. 911	OX911	0.00082	[redacted]	0.00300	0.02257	[redacted]	0.04276	[redacted]	0.00374	0.03524
7 OPERATING EXPENSE ACCT NO. 912	OX912	0.00082	[redacted]	0.00300	0.02257	[redacted]	0.04276	[redacted]	0.00374	0.03524
8 OPERATING EXPENSE ACCT NO. 913	OX913	0.00082	[redacted]	0.00300	0.02257	[redacted]	0.04276	[redacted]	0.00374	0.03524
9 OPERATING EXPENSE ACCT NO. 916	OX916	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
10 OPERATING EXPENSE ACCT NO. 920	OX920	0.00273	[redacted]	0.00559	0.03216	[redacted]	0.05099	[redacted]	0.00817	0.03939
11 OPERATING EXPENSE ACCT NO. 921	OX921	0.00273	[redacted]	0.00559	0.03216	[redacted]	0.05099	[redacted]	0.00817	0.03939
12 OPERATING EXPENSE ACCT NO. 922	OX922	0.00273	[redacted]	0.00559	0.03216	[redacted]	0.05099	[redacted]	0.00817	0.03939
13 OPERATING EXPENSE ACCT NO. 923	OX923	0.00273	[redacted]	0.00559	0.03216	[redacted]	0.05099	[redacted]	0.00817	0.03939
14 1/8 O&M LESS FUEL & PURCHASED PWR	OMX	0.00234	[redacted]	0.00508	0.03491	[redacted]	0.05662	[redacted]	0.00790	0.04319
15 DEPRECIATION EXPENSE	DEPREXP	0.00194	[redacted]	0.00419	0.03499	[redacted]	0.05223	[redacted]	0.00665	0.03498
16 AD VALOREM TAXES	PROPTAX	0.00190	[redacted]	0.00417	0.03534	[redacted]	0.05354	[redacted]	0.00668	0.03646
17 LABOR ACCOUNTS 501 THRU 507	LAB501_507	0.00119	[redacted]	0.00375	0.03930	[redacted]	0.06542	[redacted]	0.00549	0.04870
18 LABOR ACCOUNTS 511 THRU 514	LAB511_514	0.00158	[redacted]	0.00565	0.04375	[redacted]	0.08115	[redacted]	0.00710	0.06574
19 LABOR ACCOUNTS 547 THRU 550	LAB547_550	0.00109	[redacted]	0.00327	0.03817	[redacted]	0.06143	[redacted]	0.00509	0.04437
20 LABOR ACCOUNTS 552 THRU 554	LAB552_554	0.00109	[redacted]	0.00327	0.03817	[redacted]	0.06143	[redacted]	0.00509	0.04437
21 LABOR ACCOUNTS 561 THRU 567	LAB561_567	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
22 LABOR ACCOUNTS 569 THRU 573	LAB569_573	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
23 LABOR ACCOUNTS 581 THRU 589	LAB581_589	0.00290	[redacted]	0.00463	0.02154	[redacted]	0.02206	[redacted]	0.00674	0.00726

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	LIGHT & POWER TOU			LARGE INDUSTRIAL					
					LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
		SEC	PRI	TOTAL	PRI	69 KV	TOTAL	INDUSTRIAL	CURTAILABLE	TOTAL
		(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)
24 LABOR ACCOUNTS 591 THRU 598	LAB591_598	0.00361	[redacted]	0.00558	0.02532	[redacted]	0.02546	[redacted]	0.00756	0.00770
25 LABOR ACCOUNTS 902 THRU 905	LAB902_905	0.00906	[redacted]	0.01388	0.01619	[redacted]	0.02275	[redacted]	0.02121	0.03953
26 LABOR ACCOUNTS 908 THRU 910	LAB908_910	0.00082	[redacted]	0.00300	0.02257	[redacted]	0.04276	[redacted]	0.00374	0.03524
27 LABOR ACCOUNTS 912 THRU 916	LAB912_916	0.00082	[redacted]	0.00300	0.02257	[redacted]	0.04276	[redacted]	0.00374	0.03524
28 PAYROLL EXCLUDING A&G	LABORX	0.00270	[redacted]	0.00553	0.03199	[redacted]	0.05080	[redacted]	0.00809	0.03926
29 RETAIL PAYROLL EXCLUDING A&G	LABORXR	0.00270	[redacted]	0.00553	0.03199	[redacted]	0.05080	[redacted]	0.00809	0.03926
30 TOTAL PAYROLL	LABORT	0.00273	[redacted]	0.00559	0.03216	[redacted]	0.05099	[redacted]	0.00817	0.03939
31 ACCT 903 EXCL BILLING	OX903X	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
32 ACCT 903 BILLING	OX903B	0.01060	[redacted]	0.01623	0.01893	[redacted]	0.02660	[redacted]	0.02480	0.04622
33 PRODUCTION LABOR	LABPROD	0.00132	[redacted]	0.00435	0.04070	[redacted]	0.07038	[redacted]	0.00600	0.05407
34 TRANSMISSION LABOR	LABTRAN	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
35 DISTR LABOR EXCL METERING	LABDIST	0.00355	[redacted]	0.00555	0.02584	[redacted]	0.02592	[redacted]	0.00768	0.00776
36 CUST SERVICE LABOR EXCL METER & BILLING	LABCUSSV	0.00711	[redacted]	0.01150	0.02009	[redacted]	0.03209	[redacted]	0.01728	0.04210
37 METERING LABOR	LABMETER	0.00009	[redacted]	0.00038	0.00059	[redacted]	0.00234	[redacted]	0.00148	0.00323
38 BILLING LABOR	LABBILL	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-

SCHEDULE G-4
INTERNALLY DEVELOPED (CON'T)

	ALLOC	SEC (17)	PRI (18)	TOTAL (19)	PRI (20)	69 KV (21)	TOTAL (22)	INDUSTRIAL (23)	CURTAILABLE (24)	TOTAL (25)
1 SALES REVENUE	REVSALES	0.00192	[redacted]	0.00337	0.02888	[redacted]	0.04588	[redacted]	0.00748	0.04042
2 0.5*PRODPLT + 0.95*TDPLT	PTDPLTW	0.00211	[redacted]	0.00437	0.03442	[redacted]	0.05083	[redacted]	0.00709	0.03371
3 REV DEF @ CLAIMED * FACTORING	FACTC	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
4 REV DEF @ PROPOSED * FACTORING	FACTP	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
5 COS @ CLAIMED * AR REV REL TAX	REVFACC1	0.06667	[redacted]	0.13333	0.06667	[redacted]	0.13333	[redacted]	0.06667	0.13333
6 COS @ CLAIMED * LA REV RELA TAX	REVFACC2	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
7 COS @ CLAIMED * TX REV REL TAX	REVFACC3	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
8 PROPOSED REV * AR REV REL TX	REVFACP1	0.06667	[redacted]	0.13333	0.06667	[redacted]	0.13333	[redacted]	0.06667	0.13333
9 PROPOSED REV * LA REV REL TAX	REVFACP2	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
10 PROPOSED REV * TX REV REL TAX	REVFACP3	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
11 FUEL - RETAIL	FUELR	0.00164	[redacted]	0.00592	0.04437	[redacted]	0.08335	[redacted]	0.00732	0.06812
12 FUEL - WHOLESALE	FUELW	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
13 SALES REVENUE - RETAIL	REVSALESR	0.00192	[redacted]	0.00337	0.02888	[redacted]	0.04588	[redacted]	0.00748	0.04042
14 SALES REVENUE - WHOLESALE	REVSALESW	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
15 SALES REVENUE - ARKANSAS	REVSALEAR	0.00192	[redacted]	0.00337	0.02888	[redacted]	0.04588	[redacted]	0.00748	0.04042
16 SALES REVENUE - LOUISIANA	REVSALELA	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
17 SALES REVENUE - TEXAS	REVSALETX	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
18 PRODUCTION PLANT - TEXAS	PRODPLTTX	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
19 DISTRIBUTION PLANT - LOUISIANA	DISTPLTLA	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
20 RETAIL REVENUE LA	RREVLA	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
21 TAXABLE INCOME LA	TAXINCLA	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
22 TAXABLE INCOME AR	TAXINCAR	0.00357	[redacted]	0.01089	0.06000	[redacted]	0.09029	[redacted]	0.00718	0.03679
23 PLANT LA	PLANTLA	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
24 PLANT AR	PLANTAR	0.00190	[redacted]	0.00417	0.03534	[redacted]	0.05354	[redacted]	0.00668	0.03646
25 DEMAND PROD WHOLESALE	DPRODWH	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
26 DEMAND PROD ARKANSAS	DPRODAR	0.00109	[redacted]	0.00327	0.03817	[redacted]	0.06143	[redacted]	0.00509	0.04437
27 DEMAND PROD LOUISIANA	DPRODLA	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
28 DEMAND PROD TEXAS	DPRODTX	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
29 DEMAND TRAN WHOLESALE	DTRANWH	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
30 DEMAND TRAN ARKANSAS	DTRANAR	0.00140	[redacted]	0.00386	0.03918	[redacted]	0.06853	[redacted]	0.00740	0.05382
31 DEMAND TRAN LOUISIANA	DTRANLA	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
32 DEMAND TRAN TEXAS	DTRANTX	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
33 DEMAND DIST WHOLESALE	DDISTWH	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
34 DEMAND DIST ARKANSAS	DDISTAR	0.00345	[redacted]	0.00558	0.02754	[redacted]	0.02765	[redacted]	0.00820	0.00831
35 DEMAND DIST LOUISIANA	DDISTLA	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
36 DEMAND DIST TEXAS	DDISTTX	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
37 DEMAND GENERAL WHOLESALE	DGENLWH	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
38 DEMAND GENERAL ARKANSAS	DGENLAR	0.00132	[redacted]	0.00435	0.04070	[redacted]	0.07036	[redacted]	0.00600	0.05407
39 DEMAND GENERAL LOUISIANA	DGENLLA	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	LIGHT & POWER TOU			LARGE INDUSTRIAL					
					LARGE LIGHT & POWER			PULP & PAPER MILL	LP PRIMARY	
		SEC (17)	PRI (18)	TOTAL (19)	PRI (20)	69 KV (21)	TOTAL (22)	INDUSTRIAL (23)	CURTAILABLE (24)	TOTAL (25)
40 DEMAND GENERAL TEXAS	DGENLTX	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
SCHEDULE G-4										
INTERNALLY DEVELOPED (CON'T)										
1 PRODUCTION PLANT - TEXAS RETAIL	PRODPLTT	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
2 LABOR 902 & 903	LAB902_903	0.00906	[redacted]	0.01388	0.01619	[redacted]	0.02275	[redacted]	0.02121	0.03953
3 SALES REVENUE - AR RETAIL	RVSALEARR	0.00192	[redacted]	0.00337	0.02888	[redacted]	0.04588	[redacted]	0.00748	0.04042
4 SALES REVENUE - LA RETAIL	RVSALELAR	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
5 SALES REVENUE - TX RETAIL	RVSALETXR	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
6 DIST PLANT BEFORE CONTRA ADJ	DISTPLTX	0.00345	[redacted]	0.00558	0.02754	[redacted]	0.02765	[redacted]	0.00620	0.00831
7 STATE INCOME TAX	SIT	0.00349	[redacted]	0.01058	0.05886	[redacted]	0.08860	[redacted]	0.00716	0.03678
8 RETAIL PRODUCTION PLANT	PRODPLTR	0.00109	[redacted]	0.00327	0.03817	[redacted]	0.06143	[redacted]	0.00509	0.04437
9 TOTAL kWh AT GEN - ARKANSAS	KWHAR	0.00164	[redacted]	0.00592	0.04437	[redacted]	0.08335	[redacted]	0.00732	0.06812
10 TOTAL kWh AT GEN - LOUISIANA	KWHLA	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
11 TOTAL kWh AT GEN - TEXAS	KWHTX	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
12 INTANGIBLE PLANT	INTPLT	0.00230	[redacted]	0.00478	0.03399	[redacted]	0.05077	[redacted]	0.00697	0.03393
13 DEMPROD RETAIL	DEMRTAIL	0.00109	[redacted]	0.00327	0.03817	[redacted]	0.06143	[redacted]	0.00509	0.04437
14 FIT TEMPORARY DIFFERENCES	FITTEMP	0.00187	[redacted]	0.00434	0.03617	[redacted]	0.05658	[redacted]	0.00673	0.03996
15 Total Depr Expense	DEPEXP	0.00194	[redacted]	0.00419	0.03499	[redacted]	0.05223	[redacted]	0.00665	0.03498
16 AVAILABLE	AVAIL	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
17 Composite Tax Rate (FIT and AR State)	COMPTR	1.00000	[redacted]	1.00000	1.00000	[redacted]	1.00000	[redacted]	1.00000	1.00000
18 Combined Tax Gross Up (FIT and AR State)	TAX GU	1.00000	[redacted]	1.00000	1.00000	[redacted]	1.00000	[redacted]	1.00000	1.00000
19 CLAIMED FACTORING	RFACT	0.14353	[redacted]	0.14353	0.02808	[redacted]	0.02808	[redacted]	0.02808	0.02808
20 Gross Revenue Conversion Factor	REVCONV	0.99725	[redacted]	0.99725	0.99688	[redacted]	0.99688	[redacted]	0.99688	0.99688
21 AVAILABLE	AVAIL	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-
22 AVAILABLE	AVAIL	-	[redacted]	-	-	[redacted]	-	[redacted]	-	-

Supporting Schedules
(a) G-5.1 or G-5.2
(b) H-1
WP's G-2
WP's G-2 and G-3
G Class WP

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross refereneces to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	MUNICIPAL PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	LIGHTING MUNI/PUBLIC LIGHTING (28)	LIGHTING PUBLIC HIGHWAY (29)	LIGHTING PRIVATEAREA LIGHTING (30)	TOTAL (31)
SCHEDULE G-4 ALLOCATION FACTOR TABLE CAPACITY RELATED							
1 PRODUCTION ALLOCATOR	DEMPROD	0.00294	0.00128	0.00162		0.00370	0.00531
2							
3 TRANSMISSION FUNCTION	DEMTRANS	0.00338	0.00142	0.00006		0.00014	0.00020
4 D. A. ACCT 360 - LAND (MDD)	DEM360DA	4,147	1,420	4,200		9,351	13,550
5 D. A. ACCT 361 - STRUCTURES & IMPROVE	DEM361DA	4,147	1,420	4,200		9,351	13,550
6 D. A. ACCT 362 - STATION EQUIPMENT	DEM362DA	4,147	1,420	4,200		9,351	13,550
7 D. A. ACCT 364 - PRI POLES, TOWERS & FIX	DEM364DAP	4,147	1,420	4,200		9,351	13,550
8 D. A. ACCT 364 - SEC-POLES, TOWERS & FIX	DEM364DAS	4,147	1,420	4,200		9,351	13,550
9 D. A. ACCT 365 - PRI - OVRHD COND & DEVICES	DEM365DAP	4,147	1,420	4,200		9,351	13,550
10 D. A. ACCT 365 - SEC - OVRHD COND & DEVICES	DEM365DAS	4,147	1,420	4,200		9,351	13,550
11 D. A. ACCT 366 - PRI - UNDERGROUND CONDUIT	DEM366DAP	4,147	1,420	4,200		9,351	13,550
12 D. A. ACCT 366 - SEC- UNDERGROUND CONDUIT	DEM366DAS	4,147	1,420	4,200		9,351	13,550
13 D. A. ACCT 367 - PRI - UNDGRD COND & DEVICE	DEM367DAP	4,147	1,420	4,200		9,351	13,550
14 D. A. ACCT 367 - SEC - UNDGRD COND & DEVICE	DEM367DAS	4,147	1,420	4,200		9,351	13,550
15 D. A. ACCT 368 - LINE TRANSORMERS	DEM368DA	4,147	1,420	4,200		9,351	13,550
16 ANNUAL BILLING DEMAND	DEM99	72,661	31,451	0		0	0
17 SPP DEMAND	SPPDEMAND	0.00338	0.00142	0.00006		0.00014	0.00020
18 AVAILABLE SUBSTATIONS	USERSUB	-	-	-		-	-
19 AVAILABLE DIR ASSIGN SUBS	USERDASUB	-	-	-		-	-
20 AVAILABLE-PRI OVHD	USEROVHD	-	-	-		-	-
21 AVAILABLE-SECONDARY	USERSEC	-	-	-		-	-
22							
23							
24							
25 COMMODITY RELATED							
26							
27 FUEL ALLOCATION	FUEL	477,709	179,282	369,919		838,941	1,208,860
28 KWH SALES AT GENERATOR	ENERGY	16,873,633	6,163,575	12,499,534		28,743,134	41,242,668
29 SALES OF ELECTRICITY - PRESENT FUEL	REVFUEL	-	-	-		-	-
30 KWH SALES AT METER	ENERGY99	15,640,389	5,713,097	11,585,980		26,642,383	38,228,362
31 MINE CLOSING	MINECLOSE	-	-	-		-	-
32 MINE CLOSING NFIRM RETAIL	MINECLOSEN	-	-	-		-	-
33 NON FIRM FUEL PRESENT FUEL	NFREVFUEL	-	-	-		-	-
34 FUEL ADJUSTMENT	FUELADJ	-	-	-		-	-
35 NON FIRM PROPOSED FUEL RETAIL	NFPROPFUEL	-	-	-		-	-
36 PROPOSED FUEL REVENUE	PROPFUEL	-	-	-		-	-
SCHEDULE G-4 CUSTOMER RELATED							
1 ANNUAL AVERAGE CUSTOMERS	CUST99	271	483	14,239		16,468	30,707
2 YEAR END NUMBER OF CUSTOMERS	CUST	271	483	14,239		16,468	30,707
3 WEIGHTED SERVICES	CUST369	502	483	-		-	-
4 WEIGHTED METERS	CUST370	564	960	-		-	-
5 ASSIGNED CUSTOMER INSTALLATIONS	CUST371L	-	-	-		17,217	17,217
6 LIGHTING ASSIGNMENTS	CUST373	-	-	13,661		-	13,661
7 WEIGHTED METERS	CUST902	364	647	-		-	-
8 CUSTOMER ACCOUNTING	CUST903	271	483	196		-	196
9 CUSTOMER INFO EXP ALLOC	CUSTINFO	271	483	14,239		16,468	30,707
10 CUSTOMER SERVICE EXP ALLOC	CUSTSRVC	271	483	14,239		16,468	30,707
11 ACTIVE CUSTOMER DEPOSITS	CUSTDEPA	-	-	-		-	-
12 CUSTOMERS IN AR & LA	CUSTARLA	271	483	14,239		16,468	30,707
13 RETAIL CUSTOMERS	CUSTRET	271	483	14,239		16,468	30,707
14 AVAILABLE-SERVICE DROP	CUSER1	-	-	-		-	-
15 AVAILABLE SERVICE DROP	CUSER2	-	-	-		-	-
16 AVAILABLE-METERS	CUSER3	-	-	-		-	-

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

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CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	MUNICIPAL		LIGHTING			
		PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
17 AVAILABLE-METERS	CUSER4	-	-	-		-	-
18 AVAILABLE-CUSTOMER SERVICES	CUSER5	364	647	-		-	-
19 AVAILABLE-CUSTOMER SERVICES	CUSER6	-	-	-		-	-
20 CUSTOMER ENERGY SPLIT 907-916	CUSER7	0.00292	0.00234	0.04872		0.05806	0.106787
21 AVAILABLE-CUSTOMER BILLING	CUSER8	-	-	-		-	-
22 AVAILABLE-CUSTOMER BILLING	CUSER9	0	0	0		0	0
23 AVAILABLE-CUSTOMER LTG AND MISC REV	CUSER10	-	-	-		-	-
24 AVAILABLE-CUSTOMER LTG AND MISC REV	CUSER11	-	-	-		-	-
25 AVAILABLE-CUSTOMER OTHER	CUSER12	-	-	-		-	-
26							
27 REVENUE RELATED STRINGS							
28 --							
29 SALES OF ELECTRICITY-BASE	R40B	509,010	244,646	1,388,614		3,169,707	4,558,322
30 GROSS RECEIPTS FACTOR	RGR	0.0000	0.0000	0.0000		0.0000	0.0000
31 CLAIMED RATE OF RETURN	ROR	0.0521	0.0521	0.0521		0.0521	0.0521
32 CLAIMED FACTORING	RFACT	-	-	-	-	-	-
33 PROPOSED REVENUES	PREV	699,531	336,558	1,049,900		2,397,522	3,447,422
34 FEDERAL INCOME TAX RATE		0.21000	0.21000	0.21000	0.21000	0.21000	0.21000
35 LOUISIANA APPORTIONMENT FACTOR		0.24386	0.24386	0.24386	0.24386	0.24386	0.24386
36 LOUISIANA INCOME TAX RATE		0.06500	0.06500	0.06500	0.06500	0.06500	0.06500
37 ARKANSAS APPORTIONMENT FACTOR		0.24386	0.24386	0.24386	0.24386	0.24386	0.24386
38 ARKANSAS INCOME TAX RATE		0.06500	0.06500	0.06500	0.06500	0.06500	0.06500
SCHEDULE G-4							
INTERNALLY DEVELOPED							
--							
1 PRODUCTION PLANT	PRODPLT	1,789,971	780,447	983,936		2,251,172	3,235,107
2 PLANT ACCOUNT 352	PLT352	11,400	4,791	203		475	678
3 PLANT ACCOUNT 353	PLT353	474,042	199,214	8,432		19,748	28,180
4 PLANT ACCOUNTS 352 & 353	TRANSUB	485,442	204,005	8,635		20,223	28,858
5 PLANT ACCOUNTS 354, 355 & 356	TRANOHLN	827,844	347,898	14,725		34,487	49,212
6 PLANT ACCOUNT 357	TRANUGLN	1,603	674	29		67	95
7 TRANSMISSION PLANT	TRANPLT	1,390,614	584,399	24,736		57,931	82,666
8 PROD. & TRANS. PLANT	PTPLT	3,180,585	1,364,846	1,008,671		2,309,102	3,317,774
9 PLANT ACCOUNT 361	PLT361	10,612	3,634	10,748		23,929	34,677
10 PLANT ACCOUNT 362	PLT362	341,046	116,801	345,393		769,020	1,114,413
11 PLANT ACCOUNT 368	PLT368	251,291	86,062	254,494		566,633	821,127
12 PLANT ACCOUNT 370	PLT370	68,336	116,317	-		-	-
13 PLANT ACCOUNT 371	PLT371	-	-	-		8,327,075	8,327,075
14 PLANT ACCOUNT 373	PLT373	-	-	7,510,701		-	7,510,701
15 PLANT ACCOUNT 361 & 362	DISTSUB	351,658	120,436	356,140		792,950	1,149,090
16 PLANT ACCOUNT 364 & 365	DISTOHLN	828,869	283,871	839,434		1,869,007	2,708,441
17 PLANT ACCOUNT 366 & 367	DISTUGLN	343,662	117,697	348,042		774,920	1,122,962
18 DISTRIBUTION PLANT	DISTPLT	1,940,113	811,494	9,305,735		12,337,150	21,642,885
19 TRANS. & DISTR. PLANT	TDPLT	3,330,728	1,395,893	9,330,471		12,395,080	21,725,551
20 PROD., TRANS., & DISTR. PLANT	PTDPLT	5,120,699	2,176,340	10,314,406		14,646,252	24,960,659
21 GENERAL PLANT EXCL ADJUSTMENTS	GENPLTX	208,202	83,571	133,918		307,271	441,189
22 GENERAL PLANT	GENPLT	208,202	83,571	133,918		307,271	441,189
23 TOTAL ELECTRIC PLANT IN SERVICE	PLANT	5,444,029	2,305,853	10,801,696		15,587,755	26,389,452
24 NET PLANT IN SERVICE	NETPLT	3,552,881	1,501,036	7,669,648		10,836,353	18,506,001
25 RATE BASE	RBX	4,175,767	1,775,493	9,000,759		12,817,879	21,818,638
26 OPERATING EXPENSE ACCT NO. 500	OX500	10,843	4,546	6,450		14,780	21,230
27 OPERATING EXPENSE ACCT NO. 501	OX501	13,944	5,093	10,329		23,753	34,082
28 OPERATING EXPENSE ACCT NO. 502	OX502	8,903	3,882	4,894		11,197	16,092
29 OPERATING EXPENSE ACCT NO. 505	OX505	3,481	1,518	1,913		4,378	6,291
30 OPERATING EXPENSE ACCT NO. 506	OX506	11,848	5,166	6,513		14,900	21,413
31 MAINTENANCE EXPENSE ACCT NO 510	MX510	3,721	1,379	2,703		6,215	8,918
32 MAINTENANCE EXPENSE ACCT NO 511	MX511	1,621	707	891		2,039	2,930
33 MAINTENANCE EXPENSE ACCT NO 512	MX512	32,920	12,025	24,386		56,077	80,464
34 MAINTENANCE EXPENSE ACCT NO 513	MX513	4,013	1,466	2,972		6,835	9,808

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CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	MUNICIPAL		LIGHTING			
		PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
35 MAINTENANCE EXPENSE ACCT NO. 514	MX514	2,345	1,023	1,289		2,950	4,239
36 OPERATING EXPENSE ACCT NO. 546	OX546	-	-	-		-	-
37 OPERATING EXPENSE ACCT NO. 548	OX548	363	158	200		457	656
38 OPERATING EXPENSE ACCT NO. 549	OX549	-	-	-		-	-
39 MAINTENANCE EXPENSE ACCT NO. 551	MX551	-	-	-		-	-
40 MAINTENANCE EXPENSE ACCT NO. 552	MX552	-	-	-		-	-

SCHEDULE G-4
INTERNALLY DEVELOPED (CON'T)

	ALLOC	(26)	(27)	(28)	(29)	(30)	(31)
1 MAINTENANCE EXPENSE ACCT NO. 553	MX553	362	158	199		455	654
2 MAINTENANCE EXPENSE ACCT NO. 554	MX554	10	4	5		12	18
3 OPERATING EXPENSE ACCT NO. 556	OX556	1,098	479	604		1,381	1,985
4 OPERATING EXPENSE ACCT NO. 557	OX557	2,110	920	1,160		2,654	3,813
5 OPERATING EXPENSE ACCT NO. 560	OX560	5,131	2,156	91		214	305
6 OPERATING EXPENSE ACCT NO. 561	OX561	9,900	4,161	176		412	589
7 OPERATING EXPENSE ACCT NO. 562	OX562	371	156	7		15	22
8 OPERATING EXPENSE ACCT NO. 563	OX563	293	123	5		12	17
9 OPERATING EXPENSE ACCT NO. 564	OX564	-	-	-		-	-
10 OPERATING EXPENSE ACCT NO. 565	OX565	72,969	30,665	1,298		3,040	4,338
11 OPERATING EXPENSE ACCT NO. 566	OX566	1,351	568	24		56	80
12 MAINTENANCE EXPENSE ACCT NO. 568	MX568	28	12	1		1	2
13 MAINTENANCE EXPENSE ACCT NO. 569	MX569	396	166	7		16	24
14 MAINTENANCE EXPENSE ACCT NO. 570	MX570	2,430	1,021	43		101	144
15 MAINTENANCE EXPENSE ACCT NO. 571	MX571	7,129	2,996	127		297	424
16 MAINTENANCE EXPENSE ACCT NO. 572	MX572	1	0	0		0	0
17 MAINTENANCE EXPENSE ACCT NO. 573	MX573	27	11	0		1	2
18 OPERATING EXPENSE ACCT NO. 580	OX580	1,963	1,180	8,246		20,578	28,824
19 OPERATING EXPENSE ACCT NO. 581	OX581	26	11	127		168	295
20 OPERATING EXPENSE ACCT NO. 582	OX582	436	149	442		983	1,425
21 OPERATING EXPENSE ACCT NO. 583	OX583	2,700	925	2,734		6,087	8,821
22 OPERATING EXPENSE ACCT NO. 584	OX584	2,358	808	2,388		5,318	7,706
23 OPERATING EXPENSE ACCT NO. 585	OX585	-	-	33,345		-	33,345
24 OPERATING EXPENSE ACCT NO. 586	OX586	2,573	4,380	-		-	-
25 OPERATING EXPENSE ACCT NO. 587	OX587	-	-	-		126,372	126,372
26 OPERATING EXPENSE ACCT NO. 588	OX588	16,072	6,722	77,088		102,201	179,289
27 OPERATING EXPENSE ACCT NO. 589	OX589	747	313	3,584		4,752	8,336
28 MAINTENANCE EXPENSE ACCT NO. 590	MX590	309	124	2,230		1,970	4,199
29 MAINTENANCE EXPENSE ACCT NO. 591	MX591	28	10	29		64	92
30 MAINTENANCE EXPENSE ACCT NO. 592	MX592	696	238	705		1,569	2,273
31 MAINTENANCE EXPENSE ACCT NO. 593	MX593	21,528	7,373	21,802		48,543	70,345
32 MAINTENANCE EXPENSE ACCT NO. 594	MX594	1,124	385	1,138		2,534	3,673
33 MAINTENANCE EXPENSE ACCT NO. 595	MX595	83	28	84		187	271
34 MAINTENANCE EXPENSE ACCT NO. 596	MX596	-	-	64,412		-	64,412
35 MAINTENANCE EXPENSE ACCT NO. 597	MX597	354	603	-		-	-
36 MAINTENANCE EXPENSE ACCT NO. 598	MX598	-	-	-		43,021	43,021
37 OPERATING EXPENSE ACCT NO. 901	OX901	333	592	191		-	191
38 OPERATING EXPENSE ACCT NO. 902	OX902	1,385	2,462	-		-	-
39 OPERATING EXPENSE ACCT NO. 903	OX903	7,735	13,751	5,585		-	5,585
40 OPERATING EXPENSE ACCT NO. 904	OX904	1,375	661	3,750		8,560	12,310

SCHEDULE G-4
INTERNALLY DEVELOPED (CON'T)

	ALLOC	(26)	(27)	(28)	(29)	(30)	(31)
1 OPERATING EXPENSE ACCT NO. 905	OX905	52	92	30		-	30
2 OPERATING EXPENSE ACCT NO. 907	OX907	640	512	10,663		12,707	23,370
3 OPERATING EXPENSE ACCT NO. 908	OX908	2,218	1,775	36,971		44,057	81,028
4 OPERATING EXPENSE ACCT NO. 909	OX909	9	7	153		183	336
5 OPERATING EXPENSE ACCT NO. 910	OX910	5	4	91		108	199
6 OPERATING EXPENSE ACCT NO. 911	OX911	0	0	3		4	7

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	MUNICIPAL		LIGHTING			
		PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
7 OPERATING EXPENSE ACCT NO. 912	OX912	106	85	1,764		2,102	3,866
8 OPERATING EXPENSE ACCT NO. 913	OX913	(14)	(11)	(238)		(283)	(521)
9 OPERATING EXPENSE ACCT NO. 916	OX916	-	-	-		-	-
10 OPERATING EXPENSE ACCT NO. 920	OX920	23,530	13,070	66,518		108,016	174,535
11 OPERATING EXPENSE ACCT NO. 921	OX921	1,713	952	4,843		7,865	12,708
12 OPERATING EXPENSE ACCT NO. 922	OX922	(2,526)	(1,403)	(7,141)		(11,596)	(18,737)
13 OPERATING EXPENSE ACCT NO. 923	OX923	12,095	6,718	34,193		55,524	89,717
14 1/8 O&M LESS FUEL & PURCHASED PWR	OMX	39,449	19,118	66,778		108,617	175,395
15 DEPRECIATION EXPENSE	DEPREXP	146,835	62,356	311,164		443,191	754,355
16 AD VALOREM TAXES	PROPTAX	42,799	18,128	84,918		122,544	207,462
17 LABOR ACCOUNTS 501 THRU 507	LAB501_507	11,340	4,755	6,745		15,456	22,202
18 LABOR ACCOUNTS 511 THRU 514	LAB511_514	10,773	3,902	7,827		17,903	25,820
19 LABOR ACCOUNTS 547 THRU 550	LAB547_550	188	82	103		237	340
20 LABOR ACCOUNTS 552 THRU 554	LAB552_554	105	46	58		132	190
21 LABOR ACCOUNTS 561 THRU 567	LAB561_567	1,266	532	23		53	75
22 LABOR ACCOUNTS 569 THRU 573	LAB569_573	2,012	845	36		84	120
23 LABOR ACCOUNTS 581 THRU 589	LAB581_589	13,110	7,834	55,075		137,437	192,512
24 LABOR ACCOUNTS 591 THRU 598	LAB591_598	5,772	2,717	48,881		43,185	92,066
25 LABOR ACCOUNTS 902 THRU 905	LAB902_905	4,667	8,297	2,681		0	2,681
26 LABOR ACCOUNTS 908 THRU 910	LAB908_910	2,186	1,749	36,437		43,421	79,857
27 LABOR ACCOUNTS 912 THRU 916	LAB912_916	0	0	8		10	18
28 PAYROLL EXCLUDING A&G	LABORX	67,936	38,308	188,585		306,465	495,050
29 RETAIL PAYROLL EXCLUDING A&G	LABORXR	67,936	38,308	188,585		306,465	495,050
30 TOTAL PAYROLL	LABORT	80,857	44,929	228,663		371,318	599,981
31 ACCT 903 EXCL BILLING	OX903X	0	0	0		0	-
32 ACCT 903 BILLING	OX903B	7,735	13,751	5,585		0	5,585
33 PRODUCTION LABOR	LABPROD	32,539	13,061	20,930		48,023	68,952
34 TRANSMISSION LABOR	LABTRAN	6,019	2,529	107		251	358
35 DISTR LABOR EXCL METERING	LABDIST	18,834	7,353	110,092		193,099	303,191
36 CUST SERVICE LABOR EXCL METER & BILLING	LABCUSSV	7,257	9,700	57,457		65,093	122,550
37 METERING LABOR	LABMETER	3,266	5,664	0		0	-
38 BILLING LABOR	LABBILL	0	0	0		0	-

SCHEDULE G-4
INTERNALLY DEVELOPED (CON'T)

	ALLOC	PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
1 SALES REVENUE	REVSALES	509,010	244,646	1,388,614		3,169,707	4,558,322
2 0.5*PRODPLT + 0.95*TDPLT	PTDPLTW	4,059,177	1,716,322	9,355,915		12,900,912	22,256,827
3 REV DEF @ CLAIMED * FACTORING	FACTC	0	0	0		0	-
4 REV DEF @ PROPOSED * FACTORING	FACTP	-	-	-		-	-
5 COS @ CLAIMED * AR REV REL TAX	REVFACC1	1.00000	1.00000	1.00000		1.00000	2
6 COS @ CLAIMED * LA REV RELA TAX	REVFACC2	0.00000	0.00000	0.00000		0.00000	-
7 COS @ CLAIMED * TX REV REL TAX	REVFACC3	0.00000	0.00000	0.00000		0.00000	-
8 PROPOSED REV * AR REV REL TX	REVFACP1	1.00000	1.00000	1.00000		1.00000	2
9 PROPOSED REV * LA REV REL TAX	REVFACP2	0.00000	0.00000	0.00000		0.00000	-
10 PROPOSED REV * TX REV REL TAX	REVFACP3	0.00000	0.00000	0.00000		0.00000	-
11 FUEL - RETAIL	FUELR	13,944	5,033	10,329		23,753	34,082
12 FUEL - WHOLESALE	FUELW	0	0	0		0	-
13 SALES REVENUE - RETAIL	REVSALESR	509,010	244,646	1,388,614		3,169,707	4,558,322
14 SALES REVENUE - WHOLESALE	REVSALESW	0	0	0		0	-
15 SALES REVENUE - ARKANSAS	REVSALEAR	509,010	244,646	1,388,614		3,169,707	4,558,322
16 SALES REVENUE - LOUISIANA	REVSALELA	0	0	0		0	-
17 SALES REVENUE - TEXAS	REVSALETX	0	0	0		0	-
18 PRODUCTION PLANT - TEXAS	PRODPLTTX	0	0	0		0	-
19 DISTRIBUTION PLANT - LOUISIANA	DISTPLTLA	0	0	0		0	-
20 RETAIL REVENUE LA	RREVLA	0	0	0		0	-
21 TAXABLE INCOME LA	TAXINCLA	0	0	0		0	-
22 TAXABLE INCOME AR	TAXINCAR	(59,151)	(12,843)	376,145		1,493,556	1,869,701

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	MUNICIPAL		LIGHTING			
		PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
23 PLANT LA	PLANTLA	0	0	0		0	-
24 PLANT AR	PLANTAR	5,444,029	2,305,853	10,001,696		15,587,755	26,389,452
25 DEMAND PROD WHOLESALE	DPRODWH	0	0	0		0	-
26 DEMAND PROD ARKANSAS	DPRODAR	1,764,756	769,453	970,075		2,219,460	3,189,536
27 DEMAND PROD LOUISIANA	DPRODLA	0	0	0		0	-
28 DEMAND PROD TEXAS	DPRODTX	0	0	0		0	-
29 DEMAND TRAN WHOLESALE	DTRANWH	0	0	0		0	-
30 DEMAND TRAN ARKANSAS	DTRANAR	1,390,015	584,147	24,725		57,906	82,631
31 DEMAND TRAN LOUISIANA	DTRANLA	-	-	-		-	-
32 DEMAND TRAN TEXAS	DTRANTX	-	-	-		-	-
33 DEMAND DIST WHOLESALE	DDISTWH	-	-	-		-	-
34 DEMAND DIST ARKANSAS	DDISTAR	1,943,218	812,792	9,320,628		12,356,894	21,677,522
35 DEMAND DIST LOUISIANA	DDISTLA	-	-	-		-	-
36 DEMAND DIST TEXAS	DDISTTX	-	-	-		-	-
37 DEMAND GENERAL WHOLESALE	DGENLWH	-	-	-		-	-
38 DEMAND GENERAL ARKANSAS	DGENLAR	208,202	83,571	133,918		307,271	441,189
39 DEMAND GENERAL LOUISIANA	DGENLLA	-	-	-		-	-
40 DEMAND GENERAL TEXAS	DGENLTX	0	0	0		0	0
SCHEDULE G-4							
INTERNALLY DEVELOPED (CON'T)							
1 PRODUCTION PLANT - TEXAS RETAIL	PRODPLTT	0	0	0		0	-
2 LABOR 902 & 903	LAB902_903	4,659	8,282	2,677		0	2,677
3 SALES REVENUE - AR RETAIL	RVSALEARR	509,010	244,646	1,388,614		3,169,707	4,558,322
4 SALES REVENUE - LA RETAIL	RVSALELAR	0	0	0		0	-
5 SALES REVENUE - TX RETAIL	RVSALETXR	0	0	0		0	-
6 DIST PLANT BEFORE CONTRA ADJ	DISTPLTX	1,943,218	812,792	9,320,628		12,356,894	21,677,522
7 STATE INCOME TAX	SIT	(2,009)	(470)	11,391		46,061	57,452
8 RETAIL PRODUCTION PLANT	PRODPLTR	1,780,971	780,447	983,936		2,251,172	3,235,107
9 TOTAL kWh AT GEN - ARKANSAS	KWHAR	16,873,633	6,163,575	12,499,534		28,743,134	41,242,668
10 TOTAL kWh AT GEN- LOUISIANA	KWHLA	0	0	0		0	-
11 TOTAL kWh AT GEN- TEXAS	KWHTX	0	0	0		0	-
12 INTANGIBLE PLANT	INTPLT	115,129	45,943	353,372		634,232	987,604
13 DEMPROD RETAIL	DEMRTAIL	0.0029	0.0013	0.0016		0.0037	0.0053
14 FIT TEMPORARY DIFFERENCES	FITTEMP	(38,390)	(16,238)	(69,264)		(103,861)	(173,125)
15 Total Depr Expense	DEPEXP	146,835	62,356	311,164		443,191	754,355
16 AVAILABLE	AVAIL	0	0	0		0	-
17 Composite Tax Rate (FIT and AR State)	COMPTR	26.1350%	26.1350%	26.1350%		26.1350%	26.1350%
18 Combined Tax Gross Up (FIT and AR State)	TAX GU	35.3821%	35.3821%	35.3821%		35.3821%	35.3821%
19 CLAIMED FACTORING	RFACT	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
20 Gross Revenue Conversion Factor	REVCONV	1.353821	1.353821	1.353821	1.000000	1.353821	1.353821
21 AVAILABLE	AVAIL	0	0	0		0	-
SCHEDULE G-4							
RATIO TABLE							
CAPACITY RELATED							
1 PRODUCTION ALLOCATOR	DEMPROD	0.00294	0.00128	0.00161		0.00369	
2							
3 TRANSMISSION FUNCTION	DEMTRANS	0.00338	0.00142	0.00006		0.00014	
4 D. A. ACCT 360 - LAND (MDD)	DEM360DA	0.00421	0.00144	0.00427		0.00950	
5 D. A. ACCT 361 - STRUCTURES & IMPROVE	DEM361DA	0.00421	0.00144	0.00427		0.00950	
6 D. A. ACCT 362 - STATION EQUIPMENT	DEM362DA	0.00421	0.00144	0.00427		0.00950	
7 D. A. ACCT 364 - PRI-POLES, TOWERS & FIX	DEM364DAP	0.00421	0.00144	0.00427		0.00950	
8 D. A. ACCT 364 - SEC-POLES, TOWERS & FIX	DEM364DAS	0.00502	0.00172	0.00508		0.01132	
9 D. A. ACCT 365 - PRI - OVRHD COND & DEVICES	DEM365DAP	0.00421	0.00144	0.00427		0.00950	
10 D. A. ACCT 365 - SEC - OVRHD COND & DEVICES	DEM365DAS	0.00502	0.00172	0.00508		0.01132	
11 D. A. ACCT 366 - PRI - UNDERGROUND CONDUIT	DEM366DAP	0.00421	0.00144	0.00427		0.00950	
12 D. A. ACCT 366 - SEC- UNDERGROUND CONDUIT	DEM366DAS	0.00502	0.00172	0.00508		0.01132	
13 D. A. ACCT 367 - PRI - UNDGRD COND & DEVICE	DEM367DAP	0.00421	0.00144	0.00427		0.00950	

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	MUNICIPAL		LIGHTING			
		PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
14 D. A. ACCT 367 - SEC - UNDGRD COND & DEVICE	DEM367DAS	0.00502	0.00172	0.00508		0.01132	
15 D. A. ACCT 368 - LINE TRANSORMERS	DEM368DA	0.00421	0.00144	0.00427		0.00950	
16 ANNUAL BILLING DEMAND	DEM99	0.01067	0.00462	-		-	
17 SPP DEMAND	SPPDEMAND	0.00338	0.00142	0.00006		0.00014	
18 AVAILABLE-SUBSTATIONS	USERSUB	-	-	-		-	
19 AVAILABLE-DIR ASSIGN SUBS	USERDASUB	-	-	-		-	
20 AVAILABLE-PRI OVHD	USEROVHD	-	-	-		-	
21 AVAILABLE-SECONDARY	USERSEC	-	-	-		-	
22							
23							
24							
25 COMMODITY RELATED							
26 ------------------------------------							
27 FUEL ALLOCATION	FUEL	0.00397	0.00149	0.00307		0.00696	
28 KWH SALES AT GENERATOR	ENERGY	0.00409	0.00149	0.00303		0.00696	
29 SALES OF ELECTRICITY - PRESENT FUEL	REVFUEL	-	-	-		-	
30 KWH SALES AT METER	ENERGY99	0.00404	0.00148	0.00300		0.00689	
31 MINE CLOSING	MINECLOSE	-	-	-		-	
32 MINE CLOSING NFIRM RETAIL	MINECLOSEN	-	-	-		-	
33 NON FIRM FUEL PRESENT FUEL	NFREVFUEL	-	-	-		-	
34 FUEL ADJUSTMENT	FUELADJ	-	-	-		-	
35 NON FIRM PROPOSED FUEL RETAIL	NFPROPFUEL	-	-	-		-	
36 PROPOSED FUEL REVENUE	PROPFUEL	-	-	-		-	
SCHEDULE G-4							
CUSTOMER RELATED							
------------------------------------							
1 ANNUAL AVERAGE CUSTOMERS	CUST99	0.00180	0.00320	0.09445		0.10924	
2 YEAR END NUMBER OF CUSTOMERS	CUST	0.00180	0.00320	0.09445		0.10924	
3 WEIGHTED SERVICES	CUST369	0.00403	0.00388	-		-	
4 WEIGHTED METERS	CUST370	0.00368	0.00627	-		-	
5 ASSIGNED CUSTOMER INSTALLATIONS	CUST371L	-	-	-		1.00000	
6 LIGHTING ASSIGNMENTS	CUST373	-	-	1.00000		-	
7 WEIGHTED METERS	CUST902	0.00288	0.00512	-		-	
8 CUSTOMER ACCOUNTING	CUST903	0.00204	0.00363	0.00147		-	
9 CUSTOMER INFO EXP ALLOC	CUSTINFO	0.00180	0.00320	0.09445		0.10924	
10 CUSTOMER SERVICE EXP ALLOC	CUSTSRVC	0.00180	0.00320	0.09445		0.10924	
11 ACTIVE CUSTOMER DEPOSITS	CUSTDEPA	-	-	-		-	
12 CUSTOMERS IN AR & LA	CUSTARLA	0.00180	0.00320	0.09445		0.10924	
13 RETAIL CUSTOMERS	CUSTRET	0.00180	0.00320	0.09445		0.10924	
14 AVAILABLE SERVICE DROP	CUSER1	-	-	-		-	
15 AVAILABLE-SERVICE DROP	CUSER2	-	-	-		-	
16 AVAILABLE-METERS	CUSER3	-	-	-		-	
17 AVAILABLE-METERS	CUSER4	-	-	-		-	
18 AVAILABLE-CUSTOMER SERVICES	CUSER5	0.00288	0.00512	-		-	
19 AVAILABLE-CUSTOMER SERVICES	CUSER6	-	-	-		-	
20 CUSTOMER ENERGY SPLIT 907-916	CUSER7	0.00292	0.00234	0.04872		0.05806	
21 AVAILABLE-CUSTOMER BILLING	CUSER8	-	-	-		-	
22 AVAILABLE-CUSTOMER BILLING	CUSER9	0.00244	0.00284	0.00140		0.00328	
23 AVAILABLE-CUSTOMER LTG AND MISC REV	CUSER10	-	-	-		-	
24 AVAILABLE-CUSTOMER LTG AND MISC REV							
25 AVAILABLE-CUSTOMER OTHER							
REVENUE RELATED STRINGS							
------------------------------------							
29 SALES OF ELECTRICITY-BASE	R40B	0.00394	0.00189	0.01075		0.02454	
30 GROSS RECEIPTS FACTOR	RGR	0.06667	0.06667	0.06667		0.06667	
31 CLAIMED RATE OF RETURN	ROR	1.00000	1.00000	1.00000		1.00000	
32 CLAIMED FACTORING	RFACT	-	-	-		-	
33 PROPOSED REVENUES	PREV	0.00343	0.00165	0.00515		0.01177	

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
TEST YEAR ENDING DECEMBER 31, 2018

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	MUNICIPAL		LIGHTING			
		PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
34 FEDERAL INCOME TAX RATE		1.00000	1.00000	1.00000		1.00000	
35 LOUISIANA APPORTIONMENT FACTOR		1.00000	1.00000	1.00000		1.00000	
36 LOUISIANA INCOME TAX RATE		1.00000	1.00000	1.00000		1.00000	
37 ARKANSAS APPORTIONMENT FACTOR		1.00000	1.00000	1.00000		1.00000	
38 ARKANSAS INCOME TAX RATE		1.00000	1.00000	1.00000		1.00000	
SCHEDULE G-4 INTERNALLY DEVELOPED							
1 PRODUCTION PLANT	PRODPLT	0.00294	0.00128	0.00161		0.00369	
2 PLANT ACCOUNT 352	PLT352	0.00338	0.00142	0.00006		0.00014	
3 PLANT ACCOUNT 353	PLT353	0.00338	0.00142	0.00006		0.00014	
4 PLANT ACCOUNTS 352 & 353	TRANSUB	0.00338	0.00142	0.00006		0.00014	
5 PLANT ACCOUNTS 354, 355 & 356	TRANOHLN	0.00338	0.00142	0.00006		0.00014	
6 PLANT ACCOUNT 357	TRANUGLN	0.00338	0.00142	0.00006		0.00014	
7 TRANSMISSION PLANT	TRANPLT	0.00338	0.00142	0.00006		0.00014	
8 PROD. & TRANS. PLANT	PTPLT	0.00012	0.00134	0.00099		0.00226	
9 PLANT ACCOUNT 361	PLT361	0.00421	0.00144	0.00427		0.00950	
10 PLANT ACCOUNT 362	PLT362	0.00421	0.00144	0.00427		0.00950	
11 PLANT ACCOUNT 368	PLT368	0.00421	0.00144	0.00427		0.00950	
12 PLANT ACCOUNT 370	PLT370	0.00368	0.00627	-		-	
13 PLANT ACCOUNT 371	PLT371	-	-	-		1.00000	
14 PLANT ACCOUNT 373	PLT373	-	-	1.00000		-	
15 PLANT ACCOUNT 361 & 362	DISTSUB	0.00421	0.00144	0.00427		0.00950	
16 PLANT ACCOUNT 364 & 365	DISTOHLN	0.00448	0.00153	0.00454		0.01010	
17 PLANT ACCOUNT 366 & 367	DISTUGLN	0.00464	0.00159	0.00470		0.01046	
18 DISTRIBUTION PLANT	DISTPLT	0.00421	0.00176	0.02021		0.02679	
19 TRANS. & DISTR. PLANT	TDPLT	0.00382	0.00160	0.01070		0.01422	
20 PROD., TRANS., & DISTR. PLANT	PTDPLT	0.00346	0.00147	0.00696		0.00989	
21 GENERAL PLANT EXCL ADJUSTMENTS	GENPLTX	0.00341	0.00137	0.00219		0.00503	
22 GENERAL PLANT	GENPLT	0.00341	0.00137	0.00219		0.00503	
23 TOTAL ELECTRIC PLANT IN SERVICE	PLANT	0.00346	0.00147	0.00687		0.00991	
24 NET PLANT IN SERVICE	NETPLT	0.00353	0.00149	0.00763		0.01078	
25 RATE BASE	RBX	0.00354	0.00150	0.00762		0.01085	
26 OPERATING EXPENSE ACCT NO. 500	OX500	0.00315	0.00132	0.00187		0.00429	
27 OPERATING EXPENSE ACCT NO. 501	OX501	0.00409	0.00149	0.00303		0.00696	
28 OPERATING EXPENSE ACCT NO. 502	OX502	0.00294	0.00128	0.00161		0.00369	
29 OPERATING EXPENSE ACCT NO. 505	OX505	0.00294	0.00128	0.00161		0.00369	
30 OPERATING EXPENSE ACCT NO. 506	OX506	0.00294	0.00128	0.00161		0.00369	
31 MAINTENANCE EXPENSE ACCT NO. 510	MX510	0.00397	0.00147	0.00288		0.00663	
32 MAINTENANCE EXPENSE ACCT NO. 511	MX511	0.00294	0.00128	0.00161		0.00369	
33 MAINTENANCE EXPENSE ACCT NO. 512	MX512	0.00409	0.00149	0.00303		0.00696	
34 MAINTENANCE EXPENSE ACCT NO. 513	MX513	0.00409	0.00149	0.00303		0.00696	
35 MAINTENANCE EXPENSE ACCT NO. 514	MX514	0.00294	0.00128	0.00161		0.00369	
36 OPERATING EXPENSE ACCT NO. 546	OX546	-	-	-		-	
37 OPERATING EXPENSE ACCT NO. 548	OX548	0.00294	0.00128	0.00161		0.00369	
38 OPERATING EXPENSE ACCT NO. 549	OX549	-	-	-		-	
39 MAINTENANCE EXPENSE ACCT NO. 551	MX551	-	-	-		-	
40 MAINTENANCE EXPENSE ACCT NO. 552	MX552	-	-	-		-	
SCHEDULE G-4 INTERNALLY DEVELOPED (CON'T)							
1 MAINTENANCE EXPENSE ACCT NO. 553	MX553	0.00294	0.00128	0.00161		0.00369	
2 MAINTENANCE EXPENSE ACCT NO. 554	MX554	0.00294	0.00128	0.00161		0.00369	
3 OPERATING EXPENSE ACCT NO. 556	OX556	0.00294	0.00128	0.00161		0.00369	
4 OPERATING EXPENSE ACCT NO. 557	OX557	0.00294	0.00128	0.00161		0.00369	
5 OPERATING EXPENSE ACCT NO. 560	OX560	0.00338	0.00142	0.00006		0.00014	
6 OPERATING EXPENSE ACCT NO. 561	OX561	0.00338	0.00142	0.00006		0.00014	
7 OPERATING EXPENSE ACCT NO. 562	OX562	0.00338	0.00142	0.00006		0.00014	

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	MUNICIPAL		LIGHTING			
		PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
8 OPERATING EXPENSE ACCT NO. 563	OX563	0.00338	0.00142	0.00006		0.00014	
9 OPERATING EXPENSE ACCT NO. 564	OX564	-	-	-		-	
10 OPERATING EXPENSE ACCT NO. 565	OX565	0.00338	0.00142	0.00006		0.00014	
11 OPERATING EXPENSE ACCT NO. 566	OX566	0.00338	0.00142	0.00006		0.00014	
12 MAINTENANCE EXPENSE ACCT NO. 568	MX568	0.00338	0.00142	0.00006		0.00014	
13 MAINTENANCE EXPENSE ACCT NO. 569	MX569	0.00338	0.00142	0.00006		0.00014	
14 MAINTENANCE EXPENSE ACCT NO. 570	MX570	0.00338	0.00142	0.00006		0.00014	
15 MAINTENANCE EXPENSE ACCT NO. 571	MX571	0.00338	0.00142	0.00006		0.00014	
16 MAINTENANCE EXPENSE ACCT NO. 572	MX572	0.00338	0.00142	0.00006		0.00014	
17 MAINTENANCE EXPENSE ACCT NO. 573	MX573	0.00338	0.00142	0.00006		0.00014	
18 OPERATING EXPENSE ACCT NO. 580	OX580	0.00407	0.00245	0.01709		0.04255	
19 OPERATING EXPENSE ACCT NO. 581	OX581	0.00421	0.00176	0.02021		0.02679	
20 OPERATING EXPENSE ACCT NO. 582	OX582	0.00421	0.00144	0.00427		0.00950	
21 OPERATING EXPENSE ACCT NO. 583	OX583	0.00448	0.00153	0.00454		0.01010	
22 OPERATING EXPENSE ACCT NO. 584	OX584	0.00464	0.00159	0.00470		0.01046	
23 OPERATING EXPENSE ACCT NO. 585	OX585	-	-	1.00000		-	
24 OPERATING EXPENSE ACCT NO. 586	OX586	0.00368	0.00627	-		-	
25 OPERATING EXPENSE ACCT NO. 587	OX587	-	-	-		1.00000	
26 OPERATING EXPENSE ACCT NO. 588	OX588	0.00421	0.00176	0.02021		0.02679	
27 OPERATING EXPENSE ACCT NO. 589	OX589	0.00421	0.00176	0.02021		0.02679	
28 MAINTENANCE EXPENSE ACCT NO. 590	MX590	0.00424	0.00170	0.03060		0.02704	
29 MAINTENANCE EXPENSE ACCT NO. 591	MX591	0.00421	0.00144	0.00427		0.00950	
30 MAINTENANCE EXPENSE ACCT NO. 592	MX592	0.00421	0.00144	0.00427		0.00950	
31 MAINTENANCE EXPENSE ACCT NO. 593	MX593	0.00448	0.00153	0.00454		0.01010	
32 MAINTENANCE EXPENSE ACCT NO. 594	MX594	0.00464	0.00159	0.00470		0.01046	
33 MAINTENANCE EXPENSE ACCT NO. 595	MX595	0.00421	0.00144	0.00427		0.00950	
34 MAINTENANCE EXPENSE ACCT NO 596	MX596	-	-	1.00000		-	
35 MAINTENANCE EXPENSE ACCT NO. 597	MX597	0.00368	0.00627	-		-	
36 MAINTENANCE EXPENSE ACCT NO 598	MX598	-	-	-		1.00000	
37 OPERATING EXPENSE ACCT NO. 901	OX901	0.00204	0.00363	0.00117		-	
38 OPERATING EXPENSE ACCT NO 902	OX902	0.00288	0.00512	-		-	
39 OPERATING EXPENSE ACCT NO. 903	OX903	0.00190	0.00338	0.00137		-	
40 OPERATING EXPENSE ACCT NO 904	OX904	0.00394	0.00189	0.01075		0.02454	

SCHEDULE G-4
INTERNALLY DEVELOPED (CON'T)

	ALLOC	PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
1 OPERATING EXPENSE ACCT NO 905	OX905	0.00204	0.00363	0.00117		-	
2 OPERATING EXPENSE ACCT NO 907	OX907	0.00292	0.00234	0.04872		0.05806	
3 OPERATING EXPENSE ACCT NO. 908	OX908	0.00292	0.00234	0.04872		0.05806	
4 OPERATING EXPENSE ACCT NO. 909	OX909	0.00292	0.00234	0.04872		0.05806	
5 OPERATING EXPENSE ACCT NO 910	OX910	0.00292	0.00234	0.04872		0.05806	
6 OPERATING EXPENSE ACCT NO 911	OX911	0.00292	0.00234	0.04872		0.05806	
7 OPERATING EXPENSE ACCT NO 912	OX912	0.00292	0.00234	0.04872		0.05806	
8 OPERATING EXPENSE ACCT NO 913	OX913	0.00292	0.00234	0.04872		0.05806	
9 OPERATING EXPENSE ACCT NO 916	OX916	-	-	-		-	
10 OPERATING EXPENSE ACCT NO 920	OX920	0.00340	0.00189	0.00960		0.01559	
11 OPERATING EXPENSE ACCT NO 921	OX921	0.00340	0.00189	0.00960		0.01559	
12 OPERATING EXPENSE ACCT NO 922	OX922	0.00340	0.00189	0.00960		0.01559	
13 OPERATING EXPENSE ACCT NO. 923	OX923	0.00340	0.00189	0.00960		0.01559	
14 1/8 O&M LESS FUEL & PURCHASED PWR	OMX	0.00346	0.00168	0.00586		0.00954	
15 DEPRECIATION EXPENSE	DEPREXP	0.00347	0.00147	0.00734		0.01046	
16 AD VALOREM TAXES	PROPTAX	0.00346	0.00147	0.00687		0.00991	
17 LABOR ACCOUNTS 501 THRU 507	LAB501_507	0.00315	0.00132	0.00187		0.00429	
18 LABOR ACCOUNTS 511 THRU 514	LAB511_514	0.00397	0.00147	0.00288		0.00663	
19 LABOR ACCOUNTS 547 THRU 550	LAB547_550	0.00294	0.00128	0.00161		0.00369	
20 LABOR ACCOUNTS 552 THRU 554	LAB552_554	0.00294	0.00128	0.00161		0.00369	
21 LABOR ACCOUNTS 561 THRU 567	LAB561_567	0.00338	0.00142	0.00006		0.00014	
22 LABOR ACCOUNTS 569 THRU 573	LAB569_573	0.00338	0.00142	0.00006		0.00014	
23 LABOR ACCOUNTS 581 THRU 589	LAB581_589	0.00407	0.00245	0.01709		0.04255	

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	MUNICIPAL		LIGHTING			
		PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
24 LABOR ACCOUNTS 591 THRU 598	LAB591_598	0.00424	0.00170	0.03060		0.02704	
25 LABOR ACCOUNTS 902 THRU 905	LAB902_905	0.00204	0.00363	0.00117		-	
26 LABOR ACCOUNTS 908 THRU 910	LAB908_910	0.00292	0.00234	0.04872		0.05806	
27 LABOR ACCOUNTS 912 THRU 916	LAB912_916	0.00292	0.00234	0.04872		0.05806	
28 PAYROLL EXCLUDING A&G	LABORX	0.00340	0.00192	0.00943		0.01532	
29 RETAIL PAYROLL EXCLUDING A&G	LABORXR	0.00340	0.00192	0.00943		0.01532	
30 TOTAL PAYROLL	LABORT	0.00340	0.00189	0.00960		0.01559	
31 ACCT 903 EXCL BILLING	OX903X	-	-	-		-	
32 ACCT 903 BILLING	OX903B	0.00190	0.00338	0.00137		-	
33 PRODUCTION LABOR	LABPROD	0.00341	0.00137	0.00219		0.00503	
34 TRANSMISSION LABOR	LABTRAN	0.00338	0.00142	0.00006		0.00014	
35 DISTR LABOR EXCL METERING	LABDIST	0.00419	0.00163	0.02447		0.04291	
36 CUST SERVICE LABOR EXCL METER & BILLING	LABCUSSV	0.00227	0.00303	0.01793		0.02032	
37 METERING LABOR	LABMETER	0.00341	0.00588	-		-	
38 BILLING LABOR	LABBILL	-	-	-		-	

SCHEDULE G-4
INTERNALLY DEVELOPED (CON'T)

	ALLOC	PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
1 SALES REVENUE	REVSALES	0.00394	0.00189	0.01075		0.02454	
2 0.5*PRODPLT + 0.95*TDPLT	PTDPLTW	0.00358	0.00151	0.00826		0.01139	
3 REV DEF @ CLAIMED * FACTORING	FACTC	-	-	-		-	
4 REV DEF @ PROPOSED * FACTORING	FACTP	-	-	-		-	
5 COS @ CLAIMED * AR REV REL TAX	REVFACC1	0.06667	0.06667	0.06667		0.06667	
6 COS @ CLAIMED * LA REV RELA TAX	REVFACC2	-	-	-		-	
7 COS @ CLAIMED * TX REV REL TAX	REVFACC3	-	-	-		-	
8 PROPOSED REV * AR REV REL TX	REVFACP1	0.06667	0.06667	0.06667		0.06667	
9 PROPOSED REV * LA REV REL TAX	REVFACP2	-	-	-		-	
10 PROPOSED REV * TX REV REL TAX	REVFACP3	-	-	-		-	
11 FUEL - RETAIL	FUELR	0.00409	0.00149	0.00303		0.00686	
12 FUEL - WHOLESALE	FUELW	-	-	-		-	
13 SALES REVENUE - RETAIL	REVSALESR	0.00394	0.00189	0.01075		0.02454	
14 SALES REVENUE - WHOLESALE	REVSALESW	-	-	-		-	
15 SALES REVENUE - ARKANSAS	REVSALEAR	0.00394	0.00189	0.01075		0.02454	
16 SALES REVENUE - LOUISIANA	REVSALELA	-	-	-		-	
17 SALES REVENUE - TEXAS	REVSALETX	-	-	-		-	
18 PRODUCTION PLANT - TEXAS	PRODPLTTX	-	-	-		-	
19 DISTRIBUTION PLANT - LOUISIANA	DISTPLTLA	-	-	-		-	
20 RETAIL REVENUE LA	RREVLA	-	-	-		-	
21 TAXABLE INCOME LA	TAXINCLA	-	-	-		-	
22 TAXABLE INCOME AR	TAXINCAR	0.00186	0.00040	(0.01181)		(0.04690)	
23 PLANT LA	PLANTLA	-	-	-		-	
24 PLANT AR	PLANTAR	0.00346	0.00147	0.00687		0.00991	
25 DEMAND PROD WHOLESALE	DPRODWH	-	-	-		-	
26 DEMAND PROD ARKANSAS	DPRODAR	0.00294	0.00128	0.00161		0.00369	
27 DEMAND PROD LOUISIANA	DPRODLA	-	-	-		-	
28 DEMAND PROD TEXAS	DPRODTX	-	-	-		-	
29 DEMAND TRAN WHOLESALE	DTRANWH	-	-	-		-	
30 DEMAND TRAN ARKANSAS	DTRANAR	0.00338	0.00142	0.00006		0.00014	
31 DEMAND TRAN LOUISIANA	DTRANLA	-	-	-		-	
32 DEMAND TRAN TEXAS	DTRANTX	-	-	-		-	
33 DEMAND DIST WHOLESALE	DDISTWH	-	-	-		-	
34 DEMAND DIST ARKANSAS	DDISTAR	0.00421	0.00176	0.02021		0.02679	
35 DEMAND DIST LOUISIANA	DDISTLA	-	-	-		-	
36 DEMAND DIST TEXAS	DDISTTX	-	-	-		-	
37 DEMAND GENERAL WHOLESALE	DGENLWH	-	-	-		-	
38 DEMAND GENERAL ARKANSAS	DGENLAR	0.00341	0.00137	0.00219		0.00503	
39 DEMAND GENERAL LOUISIANA	DGENLLA	-	-	-		-	

Explanation: Schedule showing derivation of all allocation factors utilized in the cost of service study. All factors shall be labeled to show exact cross references to Schedule G-2 and G-3. Show data used as well as the resulting factor. The "Total Company" amount is not required if the amounts brought forward from supporting schedules are at the Arkansas level and the Company is not reporting non-Jurisdictional (non-Arkansas) amounts on the supporting schedules.

CLASS

PRODUCTION ALLOCATION METHOD
4 CP A&E

	ALLOC	MUNICIPAL		LIGHTING			
		PUMPING SERVICE (26)	MUNICIPAL SERVICE (27)	MUNI/PUBLIC LIGHTING (28)	PUBLIC HIGHWAY (29)	PRIVATEAREA LIGHTING (30)	TOTAL (31)
40 DEMAND GENERAL TEXAS	DGENLTX	-	-	-		-	-
SCHEDULE G-4 INTERNALLY DEVELOPED (CON'T)							
1 PRODUCTION PLANT - TEXAS RETAIL	PRODPLTT	-	-	-		-	
2 LABOR 902 & 903	LAB902_903	0.00204	0.00363	0.00117		-	
3 SALES REVENUE - AR RETAIL	RVSALEARR	0.00394	0.00189	0.01075		0.02454	
4 SALES REVENUE - LA RETAIL	RVSALELAR	-	-	-		-	
5 SALES REVENUE - TX RETAIL	RVSALETXR	-	-	-		-	
6 DIST PLANT BEFORE CONTRA ADJ	DISTPLTX	0.00421	0.00176	0.02021		0.02679	
7 STATE INCOME TAX	SIT	0.00193	0.00045	(0.01095)		(0.04429)	
8 RETAIL PRODUCTION PLANT	PRODPLTR	0.00294	0.00128	0.00161		0.00369	
9 TOTAL kWh AT GEN - ARKANSAS	KWHAR	0.00409	0.00149	0.00303		0.00696	
10 TOTAL kWh AT GEN- LOUISIANA	KWHLA	-	-	-		-	
11 TOTAL kWh AT GEN- TEXAS	KWHTX	-	-	-		-	
12 INTANGIBLE PLANT	INTPLT	0.00374	0.00149	0.01148		0.02060	
13 DEMPROD RETAIL	DEMRTAIL	0.00294	0.00128	0.00161		0.00369	
14 FIT TEMPORARY DIFFERENCES	FITTEMP	0.00348	0.00148	0.00628		0.00942	
15 Total Depr Expense	DEPEXP	0.00347	0.00147	0.00734		0.01046	
16 AVAILABLE	AVAIL	-	-	-		-	
17 Composite Tax Rate (FIT and AR State)	COMPTR	1.00000	1.00000	1.00000		1.00000	
18 Combined Tax Gross Up (FIT and AR State)	TAX GU	1.00000	1.00000	1.00000		1.00000	
19 CLAIMED FACTORING	RFACT	-	-	-		-	
20 Gross Revenue Conversion Factor	REVCONV	0.99680	0.99680	0.99680		0.99680	
21 AVAILABLE	AVAIL	-	-	-		-	
22 AVAILABLE	AVAIL	-	-	-		-	

Supporting Schedules
(a) G-5.1 or G-5.2
(b) H-1
WP's G-2
WP's G-2 and G-3
G Class WP

SOUTHWESTERN ELECTRIC POWER COMPANY
LOAD DATA AND RATE SCHEDULE or CLASS SCHEDULE INFORMATION
TEST YEAR ENDING DECEMBER 31, 2018
DOCKET NO. 19-008-U

Explanation: Schedule showing operating characteristics fo the system for the test year and the pro forma year.

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SOUTHWESTERN ELECTRIC POWER COMPANY
LOAD DATA AND RATE SCHEDULE or CLASS SCHEDULE INFORMATION
TEST YEAR ENDING DECEMBER 31, 2018
DOCKET NO. 19-008-U

Schedule G-5.1(1)

MONTHLY PEAK DEMANDS (Test Year Only)

(1) Line No.	(2) Month	(3) Total System kW	(4) Date	(5) Time (CST Hour Ending)	(6) Arkansas kW @ System Peak
1	Jan-18	4,792,457	1/17/2018	9:00 AM	863,432
2	Feb-18	3,906,889	2/8/2018	9:00 AM	708,088
3	Mar-18	3,170,826	3/8/2018	8:00 AM	637,169
4	Apr-18	2,971,784	4/16/2018	8:00 AM	630,459
5	May-18	4,354,982	5/30/2018	5:00 PM	922,691
6	Jun-18	4,634,523	6/28/2018	4:00 PM	1,027,295
7	*	*	*	*	*
8	*	*	*	*	*
9	*	*	*	*	*
10	*	*	*	*	*
11	*	*	*	*	*
12	*	*	*	*	*

*Data will be provided in update to actuals

SOUTHWESTERN ELECTRIC POWER COMPANY
LOAD DATA AND RATE SCHEDULE or CLASS SCHEDULE INFORMATION
TEST YEAR ENDING DECEMBER 31, 2018
DOCKET NO. 19-008-U

Schedule G-5.1(2)

TEST YEAR ENDING DECEMBER 31, 2018 MONTHLY PEAK DEMANDS
(Includes Weather Normalization and Customer Adjustments)

(1) Line No.	(2) Month	(3) Total System kW	(4) Date	(5) Time (CST Hour Ending)	(6) Arkansas kW @ System Peak
1	Jan-18	4,336,059	1/17/2018	9:00 AM	781,205
2	Feb-18	3,897,236	2/8/2018	9:00 AM	706,339
3	Mar-18	3,362,414	3/8/2018	8:00 AM	675,668
4	Apr-18	2,919,472	4/16/2018	8:00 AM	619,361
5	May-18	3,855,696	5/30/2018	5:00 PM	816,907
6	Jun-18	4,384,257	6/28/2018	4:00 PM	971,821
7	Jul-18	4,757,585	7/31/2018	5:00 PM	996,622
8	Aug-18	4,812,678	8/6/2018	5:00 PM	1,041,051
9	Sep-18	4,343,785	9/24/2018	5:00 PM	939,855
10	Oct-18	3,626,395	10/5/2018	5:00 PM	798,682
11	Nov-18	3,336,042	11/23/2018	9:00 AM	650,655
12	Dec-18	3,880,268	12/12/2018	9:00 AM	708,428

TEST YEAR ENDING DECEMBER 31, 2019 MONTHLY PEAK DEMANDS
(Includes Weather Normalization and Customer Adjustments)

(1) Line No.	(2) Month	(3) Total System kW	(4) Date	(5) Time (CST Hour Ending)	(6) Arkansas kW @ System Peak
1	Jan-18	4,336,059	1/17/2018	9:00	781,205
2	Feb-18	3,897,236	2/8/2018	9:00	706,339
3	Mar-18	3,362,414	3/8/2018	8:00	675,668
4	Apr-18	2,919,472	4/16/2018	8:00	619,361
5	May-18	3,855,696	5/30/2018	17:00	816,907
6	Jun-18	4,384,257	6/28/2018	16:00	971,821
7	Jul-18	4,757,585	7/31/2018	17:00	996,622
8	Aug-18	4,812,678	8/6/2018	17:00	1,041,051
9	Sep-18	4,343,785	9/24/2018	17:00	939,855
10	Oct-18	3,626,395	10/5/2018	17:00	798,682
11	Nov-18	3,336,042	11/23/2018	9:00	650,655
12	Dec-18	3,880,268	12/12/2018	9:00	708,428

SOUTHWESTERN ELECTRIC POWER COMPANY
LOAD DATA AND RATE SCHEDULE or CLASS SCHEDULE INFORMATION
TEST YEAR ENDING DECEMBER 31, 2018
DOCKET NO. 19-008-U

Schedule G-5.1(3)

Customer		Date	MW	MWh/month
Customer #1 (Texas)	Expansion	Mar-19	2.5	540

SOUTHWESTERN ELECTRIC POWER COMPANY
LOAD DATA AND RATE SCHEDULE or CLASS SCHEDULE INFORMATION
TEST YEAR ENDING DECEMBER 31, 2018
DOCKET NO. 19-008-U

CLASS

Residential Service

This class includes rates for residential, single family, or individual family apartments. No commercial use is allowed on these rates. Included in this class are rate schedules: Residential Basic and Residential with electric heating appliances (closed).

General Service

This class includes rates for commercial customers not exceeding 50 kW and lighting-only for stadium, ball-park or recreational night lighting. Included in this class are rate schedules: General Service and Recreational Lighting.

Light and Power

This class includes rates for commercial and small industrial taking service under secondary and primary voltage with demand requirements over 50 kW. Included in this class are rate schedules: Light and Power Primary and Light and Power Secondary.

Light and Power Time of Use

This rates is an optional rate for customers having a maximum demand of 500 kW under secondary or primary voltage. Included in this rate: Light and Power Time of Use Primary and Secondary.

Industrial Class

This class is for customers that take service at the transmission voltage with demand and energy rates. Included in this rate: Large Light and Power and Pulp and Paper Mills.

Municipal

This class is for municipal pumping and service. Included in this rate: Municipal Service and Municipal Pumping.

Lighting

This class is includes lighting service to municipalities for company-owned street and parkway lighting and company-owned lighting service for residential, commercial, and industrial customers for outdoor, area, and private lighting. This class includes: Municipal Publice and Highway Lighting and Private, Outdoor and Area Lighting.

SOUTHWESTERN ELECTRIC POWER COMPANY
LOAD DATA AND RATE SCHEDULE or CLASS SCHEDULE INFORMATION
TEST YEAR ENDING DECEMBER 31, 2018
DOCKET NO. 19-008-U

ANNUAL LOAD FACTOR (Pro forma year ending December 31, 2019)

Group No.	Rate Class	(b) Load Factor	(c) Non-Coincident Peak Annual	(d) SPP Coincident Peak Annual	(d) SWEPCO Coincident Peak Annual
1	Residential	35%	306,351	238,377	238,377
2	Residential w/Heating	37%	61,867	39,385	39,385
3	Lighting	37%	8,179	0	0
4	Recreational Lighting	34%	1,183	0	0
5	General Service	42%	102,629	82,541	82,541
6	Lighting and Power Sec	55%	228,595	196,142	196,142
7	Lighting and Power Pri	68%	91,103	77,117	77,117
8	Lighting and Power TOU Sec	22%	3,225	710	710
9	Lighting and Power TOU Pri	66%	2,903	0	0
10	LLP Primary W/SBMAA	39%	23,652	17,175	17,175
11	Pulp and Paper Mill	53%	52,972	32,593	32,593
12	Lighting and Power Curtailable	29%	11,147	4,718	4,718
13	LLP Trans 69kV	62%	28,731	19,723	19,723
14	LLP Primary	76%	14,154	12,891	12,891
15	Muni and Public Lighting	36%	3,673	0	0
16	Muni Service	52%	1,242	999	999
17	Muni Pumping	54%	3,321	2,438	2,438

Month	Rate Class	(c) Non-Coincident Peak Monthly	(d) SPP Coincident Peak Monthly	(d) SWEPCO Coincident Peak Monthly
1	Residential	224,686	212,075	212,075
2	Residential	219,645	208,908	192,985
3	Residential	160,847	160,176	151,627
4	Residential	153,738	127,411	122,438
5	Residential	155,488	124,249	155,488
6	Residential	201,005	195,199	197,073
7	Residential	268,297	263,235	261,319
8	Residential	306,351	238,377	238,377
9	Residential	297,717	294,733	294,733
10	Residential	213,294	213,193	213,193
11	Residential	127,513	100,058	100,058
12	Residential	192,064	153,884	153,884
1	Residential w/Heating	61,867	58,394	58,394

Month	Rate Class	Non-Coincident Peak Monthly	SPP Coincident Peak Monthly	SWEPCO Coincident Peak Monthly
2	Residential w/Heating	59,818	56,894	52,558
3	Residential w/Heating	40,118	39,951	37,818
4	Residential w/Heating	35,216	29,185	28,046
5	Residential w/Heating	30,832	24,638	30,832
6	Residential w/Heating	34,391	33,397	33,718
7	Residential w/Heating	44,117	43,285	42,970
8	Residential w/Heating	50,616	39,385	39,385
9	Residential w/Heating	49,321	48,827	48,827
10	Residential w/Heating	40,672	40,653	40,653
11	Residential w/Heating	27,747	21,773	21,773
12	Residential w/Heating	47,093	37,732	37,732
1	Lighting	5,523	0	0
2	Lighting	6,577	0	0
3	Lighting	6,401	0	427
4	Lighting	7,311	0	0
5	Lighting	7,717	0	0
6	Lighting	8,179	0	0
7	Lighting	7,871	0	0
8	Lighting	7,561	0	0
9	Lighting	7,049	0	0
10	Lighting	5,859	0	0
11	Lighting	6,028	1,005	1,005
12	Lighting	5,745	0	0
1	Recreational Lighting	859	0	0
2	Recreational Lighting	953	0	0
3	Recreational Lighting	973	0	65
4	Recreational Lighting	1,183	0	0
5	Recreational Lighting	1,160	0	0
6	Recreational Lighting	1,079	0	0
7	Recreational Lighting	856	0	0
8	Recreational Lighting	764	0	0
9	Recreational Lighting	826	0	0
10	Recreational Lighting	776	0	0
11	Recreational Lighting	781	130	130
12	Recreational Lighting	613	0	0
1	General Service	71,005	56,109	56,109
2	General Service	76,199	50,449	53,228
3	General Service	61,670	40,594	35,355
4	General Service	59,763	35,098	36,741
5	General Service	61,408	56,965	61,262
6	General Service	82,429	77,903	75,792
7	General Service	90,357	90,347	85,992
8	General Service	102,629	82,524	82,524

Month	Rate Class	Non-Coincident Peak Monthly	SPP Coincident Peak Monthly	SWEPCO Coincident Peak Monthly
9	General Service	95,822	83,486	83,486
10	General Service	76,919	62,689	62,689
11	General Service	59,925	43,741	43,741
12	General Service	63,378	45,607	45,607
1	Lighting and Power Sec	154,269	131,295	131,295
2	Lighting and Power Sec	166,290	129,634	134,354
3	Lighting and Power Sec	160,688	118,932	103,207
4	Lighting and Power Sec	172,138	116,842	109,370
5	Lighting and Power Sec	160,239	139,959	145,646
6	Lighting and Power Sec	187,519	182,697	187,512
7	Lighting and Power Sec	196,209	186,302	194,575
8	Lighting and Power Sec	212,952	196,141	196,141
9	Lighting and Power Sec	228,595	214,074	214,074
10	Lighting and Power Sec	202,797	180,635	180,635
11	Lighting and Power Sec	188,825	148,716	148,716
12	Lighting and Power Sec	173,203	137,807	137,807
1	Lighting and Power Pri	68,735	63,019	63,019
2	Lighting and Power Pri	75,800	70,013	68,729
3	Lighting and Power Pri	68,128	60,003	58,332
4	Lighting and Power Pri	78,326	69,230	71,171
5	Lighting and Power Pri	77,470	72,182	72,750
6	Lighting and Power Pri	86,855	80,247	79,219
7	Lighting and Power Pri	85,957	75,453	81,682
8	Lighting and Power Pri	82,934	77,384	77,384
9	Lighting and Power Pri	91,103	87,087	87,087
10	Lighting and Power Pri	79,075	71,864	71,864
11	Lighting and Power Pri	80,309	69,834	69,834
12	Lighting and Power Pri	82,246	74,780	74,780
1	Lighting and Power TOU Sec	2,454	1,757	1,757
2	Lighting and Power TOU Sec	3,225	551	560
3	Lighting and Power TOU Sec	2,507	543	464
4	Lighting and Power TOU Sec	2,685	538	503
5	Lighting and Power TOU Sec	3,061	896	1,134
6	Lighting and Power TOU Sec	1,884	1,081	1,098
7	Lighting and Power TOU Sec	2,074	977	834
8	Lighting and Power TOU Sec	2,227	710	710
9	Lighting and Power TOU Sec	2,025	791	791
10	Lighting and Power TOU Sec	2,733	848	848
11	Lighting and Power TOU Sec	2,669	641	641
12	Lighting and Power TOU Sec	2,929	686	686
1	Lighting and Power TOU Pri	2,291	2,051	2,051
2	Lighting and Power TOU Pri	2,705	1,843	2,173
3	Lighting and Power TOU Pri	2,714	2,054	2,041

Month	Rate Class	Non-Coincident Peak Monthly	SPP Coincident Peak Monthly	SWEPCO Coincident Peak Monthly
4	Lighting and Power TOU Pri	2,393	2,137	1,765
5	Lighting and Power TOU Pri	2,792	2,225	2,239
6	Lighting and Power TOU Pri	2,424	2,145	2,151
7	Lighting and Power TOU Pri	2,455	0	0
8	Lighting and Power TOU Pri	2,903	0	0
9	Lighting and Power TOU Pri	2,295	0	0
10	Lighting and Power TOU Pri	2,256	2,013	2,013
11	Lighting and Power TOU Pri	2,452	1,896	1,896
12	Lighting and Power TOU Pri	2,419	2,142	2,142
1	LLP Primary W/SBMAA	11,270	9,257	9,257
2	LLP Primary W/SBMAA	12,478	8,933	9,010
3	LLP Primary W/SBMAA	15,699	8,199	7,656
4	LLP Primary W/SBMAA	17,087	13,373	13,406
5	LLP Primary W/SBMAA	19,037	17,830	18,699
6	LLP Primary W/SBMAA	19,383	15,290	15,368
7	LLP Primary W/SBMAA	15,843	15,530	14,753
8	LLP Primary W/SBMAA	17,624	17,175	17,175
9	LLP Primary W/SBMAA	23,652	23,142	23,142
10	LLP Primary W/SBMAA	18,526	13,371	13,371
11	LLP Primary W/SBMAA	13,020	8,807	8,807
12	LLP Primary W/SBMAA	13,102	8,785	8,785
1	Pulp and Paper Mill	52,972	33,864	33,864
2	Pulp and Paper Mill	43,797	15,893	19,375
3	Pulp and Paper Mill	43,709	31,859	36,756
4	Pulp and Paper Mill	42,646	29,523	29,177
5	Pulp and Paper Mill	49,324	37,425	24,389
6	Pulp and Paper Mill	47,397	29,702	33,739
7	Pulp and Paper Mill	42,111	34,595	35,777
8	Pulp and Paper Mill	42,986	32,593	32,593
9	Pulp and Paper Mill	43,069	32,446	32,446
10	Pulp and Paper Mill	46,859	30,658	30,658
11	Pulp and Paper Mill	38,930	32,584	32,584
12	Pulp and Paper Mill	35,793	21,460	21,460
1	Lighting and Power Curtailable	10,329	4,962	4,962
2	Lighting and Power Curtailable	10,386	7,214	5,145
3	Lighting and Power Curtailable	8,740	7,747	5,087
4	Lighting and Power Curtailable	11,147	5,907	4,771
5	Lighting and Power Curtailable	10,183	2,086	3,530
6	Lighting and Power Curtailable	10,701	2,654	2,736
7	Lighting and Power Curtailable	9,233	3,381	3,576
8	Lighting and Power Curtailable	9,295	4,718	4,718
9	Lighting and Power Curtailable	9,657	5,556	5,556
10	Lighting and Power Curtailable	9,704	5,029	5,029

Month	Rate Class	Non-Coincident Peak Monthly	SPP Coincident Peak Monthly	SWEPCO Coincident Peak Monthly
11	Lighting and Power Curtailable	9,403	2,155	2,155
12	Lighting and Power Curtailable	9,132	4,303	4,303
1	LLP Trans 69kV	18,988	15,316	15,316
2	LLP Trans 69kV	20,522	17,302	17,521
3	LLP Trans 69kV	19,572	15,356	15,060
4	LLP Trans 69kV	22,298	17,587	15,797
5	LLP Trans 69kV	20,427	18,817	18,071
6	LLP Trans 69kV	21,042	19,323	19,467
7	LLP Trans 69kV	22,933	19,575	19,591
8	LLP Trans 69kV	21,617	19,723	19,723
9	LLP Trans 69kV	23,956	21,977	21,977
10	LLP Trans 69kV	22,110	19,451	19,451
11	LLP Trans 69kV	28,731	26,042	26,042
12	LLP Trans 69kV	22,927	18,799	18,799
1	LLP Primary	11,139	9,236	9,236
2	LLP Primary	12,380	10,904	11,940
3	LLP Primary	10,627	9,814	9,802
4	LLP Primary	11,675	10,418	11,001
5	LLP Primary	12,792	10,974	5,519
6	LLP Primary	12,983	12,139	12,062
7	LLP Primary	13,144	12,916	12,438
8	LLP Primary	13,171	12,891	12,891
9	LLP Primary	14,154	12,878	12,878
10	LLP Primary	11,423	10,872	10,872
11	LLP Primary	12,360	10,361	10,361
12	LLP Primary	12,374	11,832	11,832
1	Muni and Public Lighting	2,453	0	0
2	Muni and Public Lighting	2,883	0	0
3	Muni and Public Lighting	2,829	0	189
4	Muni and Public Lighting	3,213	0	0
5	Muni and Public Lighting	3,395	0	0
6	Muni and Public Lighting	3,673	0	0
7	Muni and Public Lighting	3,471	0	0
8	Muni and Public Lighting	3,210	0	0
9	Muni and Public Lighting	3,021	0	0
10	Muni and Public Lighting	2,675	0	0
11	Muni and Public Lighting	2,574	429	429
12	Muni and Public Lighting	2,407	0	0
1	Muni Service	1,242	1,163	1,163
2	Muni Service	1,096	1,026	1,038
3	Muni Service	880	718	784
4	Muni Service	764	541	660
5	Muni Service	762	642	723

Month	Rate Class	Non-Coincident Peak Monthly	SPP Coincident Peak Monthly	SWEPCO Coincident Peak Monthly
6	Muni Service	947	875	886
7	Muni Service	1,063	1,046	1,021
8	Muni Service	1,006	999	999
9	Muni Service	1,039	956	956
10	Muni Service	866	790	790
11	Muni Service	800	606	606
12	Muni Service	1,010	775	775
1	Muni Pumping	2,774	1,189	1,189
2	Muni Pumping	3,285	1,481	2,040
3	Muni Pumping	2,932	2,195	2,257
4	Muni Pumping	2,569	1,707	2,009
5	Muni Pumping	2,252	2,168	1,775
6	Muni Pumping	2,586	2,366	2,255
7	Muni Pumping	2,087	2,001	1,955
8	Muni Pumping	3,321	2,438	2,438
9	Muni Pumping	2,867	2,450	2,450
10	Muni Pumping	2,221	1,925	1,925
11	Muni Pumping	2,428	1,721	1,721
12	Muni Pumping	2,950	2,475	2,475

ENERGY LOSSES

Transmission 138kV	138-T	98.223%
Transmission 69kV	69-T	96.989%
Primary Substation	Pri-Sub	96.977%
Primary	Pri	95.206%
Secondary	Sec	92.691%

See Workpaper G-5.1 4e (page 2)

Explanation: Schedule comparing revenues from each rate class for the pro forma year, at present and proposed rates.

		PRESENT				PROPOSED				PROPOSED INCREASE (A)			
(1)	(2)	(3)	(5)	(6)	(7)	(8)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
LINE NO.	Rate Class	Rate Schedule Revenue	Fuel	Other Itemized Riders*	Total Revenue	Rate Schedule Revenue	Fuel	Other Itemized Riders**	Total Revenue	Rate Schedule Revenue	%	Total Revenue	%
1	Residential Service	$ 45,329,688	$ 30,832,151	$ 14,094,589	$ 90,256,428	$ 72,096,294	$ 30,832,151	$ 9,170,993	$ 112,099,439	$ 26,766,606	59.05%	$ 21,843,011	24.20%
2	*Residential Service - Electric Heating Appliance*	$ 8,315,373	$ 6,704,551	$ 3,064,914	$ 18,084,839	$ 13,225,247	$ 6,704,551	$ 1,994,262	$ 21,924,060	$ 4,909,874	59.05%	$ 3,839,222	21.23%
3	*General Service*	$ 15,699,958	$ 12,245,729	$ 5,010,644	$ 32,956,331	$ 23,152,861	$ 12,245,729	$ 2,890,870	$ 38,289,460	$ 7,452,903	47.47%	$ 5,333,128	16.18%
4	*Recreational Lighting*	$ 99,536	$ 115,774	$ 43,573	$ 258,883	$ 142,151	$ 115,774	$ 27,337	$ 285,263	$ 42,615	42.81%	$ 26,380	10.19%
5	*Lighting & Power Secondary*	$ 30,742,086	$ 35,521,797	$ 11,696,274	$ 77,960,157	$ 51,719,681	$ 35,521,797	$ 7,294,345	$ 94,535,823	$ 20,977,595	68.24%	$ 16,575,666	21.26%
6	*Lighting & Power Primary*	$ 12,101,967	$ 17,158,736	$ 4,328,081	$ 33,588,784	$ 19,889,732	$ 17,158,736	$ 1,901,024	$ 38,949,491	$ 7,787,765	64.35%	$ 5,360,707	15.96%
7	*Lighting & Power Primary Curtailable*	$ 966,899	$ 904,141	$ 310,440	$ 2,181,480	$ 1,832,894	$ 904,141	$ 136,907	$ 2,873,942	$ 865,996	89.56%	$ 692,462	31.74%
8	*Lighting & Power TOU Secondary*	$ 248,498	$ 203,189	$ 82,222	$ 533,908	$ 553,854	$ 203,189	$ 47,978	$ 805,021	$ 305,356.69	122.88%	$ 271,113	50.78%
9	*Lighting & Power TOU Primary*	$ 187,060	$ 528,460	$ 183,392	$ 898,912	$ 416,955	$ 528,460	$ 100,350	$ 1,045,765	$ 229,895.01	122.90%	$ 146,852	16.34%
10	Large Lighting & Power Primary	$ 1,785,790	$ 2,960,569	$ 498,772	$ 5,245,131	$ 2,935,094	$ 2,960,569	$ 158,604	$ 6,054,267	$ 1,149,304.27	64.36%	$ 809,136	15.43%
11	Large Lighting & Power Primary Firm w/SBMAA	$ 1,945,510	$ 2,518,347	$ 472,674	$ 4,936,531	$ 3,197,541	$ 2,518,347	$ 134,913	$ 5,850,801	$ 1,252,030.99	64.35%	$ 914,270	18.52%
12	Large Lighting & Power Transmission	$ 2,195,911	$ 4,862,739	$ 298,272	$ 7,356,922	$ 3,816,911	$ 4,862,739	$ -	$ 8,679,650	$ 1,620,999.93	73.82%	$ 1,322,728	17.98%
13	Pulp & Paper Mill Service	$ 4,254,656	$ 7,584,873	$ 559,390	$ 12,398,919	$ 6,249,063	$ 7,584,873	$ -	$ 13,833,936	$ 1,994,407.21	46.88%	$ 1,435,017	11.57%
14	Municipal Service	$ 244,646	$ 185,213	$ 74,278	$ 504,137	$ 336,558	$ 185,213	$ 43,814	$ 565,584	$ 91,911.54	37.57%	$ 61,447	12.19%
15	Municipal Pumping	$ 509,010	$ 507,046	$ 211,293	$ 1,227,348	$ 699,531	$ 507,046	$ 119,946	$ 1,326,523	$ 190,520.75	37.43%	$ 99,174	8.08%
16	Municipal Lighting & Public Street & Highway Lighting	$ 1,388,614	$ 375,606	$ 100,432	$ 1,864,652	$ 1,049,900	$ 375,606	$ 93,313	$ 1,518,819	$ (338,714.20)	-24.39%	$ (345,832)	-18.55%
17	Private/Area/Outdoor Lighting	$ 3,169,707	$ 863,719	$ 230,688	$ 4,264,115	$ 2,397,522	$ 863,719	$ 214,578	$ 3,475,819	$ (772,185)	-24.36%	($788,296)	-18.49%
18	Total Arkansas Rate Schedule Revenues	$ 129,184,908	$ 124,072,640	$ 41,259,929	$ 294,517,477	$ 203,711,789	$ 124,072,640	$ 24,329,234	$ 352,113,663	$ 74,526,881	57.69%	$ 57,596,186	19.56%

*Present Riders: EECR, Alternative Generation Recovery, Environmental Compliance

***Proposed Riders: EECR w/ LCFC Reduction and Distribution Reliability Request*

Supporting Schedules
(a) H-2
(b) G-1

Recap Schedules
(A) G-1

Southwestern Electric Power Company

Revenue Distribution Percent Change 59.05%

RS 15 38 62		Present Price	Proposed Price
Customer Charge		$7.75	$10.00
May-September			
	0-1,500 kWh	$0.0442	$0.0702
	over 1,500 kWh	$0.0534	$0.0919
October-April			
	all kWh	$0.0358	$0.0610

Revenue Distribution Percent Change 59.05%

RS - Electric Heating 22 39		Present Price	Proposed Price
Customer Charge		$7.75	$10.00
May-September			
	0-1,500 kWh	$0.0442	$0.0702
	over 1,500 kWh	$0.0534	$0.0919
October-April			
	0-500 kWh	$0.0358	$0.0610
	over 500 kWh	$0.0230	$0.0380

Revenue Distribution Percent Change 47.43%

GS 220_200_222_50_282	Present Price	Proposed Price
Customer Charge	$8.60	$10.60
May-September All kWh	$0.0307	$0.0456
October-April All kWh	$0.0252	$0.0373
Demand Charge 0-6 kW	$0.00	$0.00
Demand Charge over 6 kW	$4.20	$6.51

Revenue Distribution Percent Change 47.43%

Recreational Lighting	Present Price	Proposed Price
Customer Charge	$8.60	$10.60
May-September All kWh	$0.0257	$0.0373
October-April All kWh	$0.0257	$0.0373

Revenue Distribution Percent Change 37.50%

MS 544	Present Price	Proposed Price
Customer Charge	$5.35	$7.36
May-September All kWh	$0.0405	$0.0557
October-April All kWh	$0.0359	$0.0494
Minimum Charge per kW	$1.28	$1.76
But not less then	$5.35	$7.36

Revenue Distribution Percent Change 37.50%

MP 550_540_549	Present Price	Proposed Price
Customer Charge	$5.35	$7.36
May-September All kWh	$0.0358	$0.0492
October-April All kWh	$0.0310	$0.0426
Minimum Charge per kW	$1.28	$1.76
But not less then	$5.35	$7.36

Revenue Distribution Percent Change 68.23%

LP Sec 240_241_243_60	Present Price	Proposed Price
Customer Charge	$0.00	$0.00
May-September		
All kWh	$0.0160	$0.0270
Demand Charge 0-50 kW (minimum)	$377.50	$636.50
Demand Charge over 50 kW	$7.55	$12.73
October-April		
All kWh	$0.0047	$0.0079
Demand Charge 0-50 kW (minimum)	$305.00	$511.00
Demand Charge over 50 kW	$6.10	$10.22

Revenue Distribution Percent Change 122.90%

LP Sec TOU 223	Present Price	Proposed Price	
Customer Charge	$0.00	$0.00	
On Peak 1-7pm July, August, September			
All kWh	$0.0556	$0.1039	
Demand Charge 0-50 kW	$582.50	$1,066.50	
Demand Charge over 50 kW	$11.65	$21.33	
Off Peak - All Hours Other Than On Peak			
All kWh	$0.0070	$0.0161	$0.0159
Demand Charge 0-50 kW (minimum)	$162.50	$441.00	
Demand Charge over 50 kW	$3.25	$8.82	

Revenue Distribution Percent Change 122.90%

LP Pri TOU 224	Present Price	Proposed Price
Customer Charge	$0.00	$0.00
On Peak 1-7pm July, August, September		
All kWh	$0.0554	$0.1005
Demand Charge 0-50 kW	$550.00	$826.00
Demand Charge over 50 kW	$11.00	$16.52
Off Peak - All Hours Other Than On Peak		
All kWh	$0.0068	$0.0142
Demand Charge 0-50 kW (minimum)	$132.50	$321.50
Demand Charge over 50 kW	$2.65	$6.43

Revenue Distribution Percent Change 64.62%

LP Primary - 246_249_250_251_66	Present Price	Proposed Price
Customer Charge	$0.00	$0.00
May-September		
All kWh	$0.01565	$0.02573
Demand Charge 0-50 kW (minimum)	$340.00	$558.00
Demand Charge over 50 kW	$6.80	$11.16
October-April		
All kWh	$0.00450	$0.0074
Demand Charge 0-50 kW (minimum)	$267.50	$440.00
Demand Charge over 50 kW	$5.35	$8.80

Revenue Distribution Percent Change 64.62%

LLP Primary 346	Present Price	Proposed Price
Customer Charge	$0.00	$0.00
May-September		
All kWh	$0.01565	$0.02573
Demand Charge 10,000 kW minimum	$68,000	$111,600
All kW over 10,000	$6.80	$11.16
October-April		
All kWh	$0.00450	$0.0074
Demand Charge 10,000 kW minimum	$53,500	$88,000
All kW over 10,000	$5.35	$8.80

Revenue Distribution Percent Change 67.42%

LLP Transmission 342	Present Price	Proposed Price
Customer Charge	$0.00	$0.00
May-September		
All kWh	$0.01330	$0.0223
Demand Charge 10,000 kW minimum	$52,600	$88,100
All kW over 10,000	$5.26	$8.81
October-April		
All kWh	$0.00360	$0.0060
Demand Charge 10,000 kW minimum	$39,700	$66,500
All kW over 10,000	$3.97	$6.65

Revenue Distribution Percent Change 46.89%

Pulp & Paper Mill 326	Present Price	Proposed Price
Customer Charge	$0.00	$0.00
All kWh	$0.00700	$0.0103
Demand Charge 200,000 kW minimum	$105,000	$154,200
All kW over 20,000	$5.25	$7.71

Revenue Distribution Percent Change 46.89%

	Daily Rate Per kW	Minimum Rate	Minimum Charge	Minimum kW
Pulp & Paper Backup Power Current	0.220	0.91	$13,650	15,000

	Daily Rate Per kW	Minimum Rate	Minimum Charge	Minimum kW
Pulp & Paper Backup Power Proposed	0.310	1.33	$19,950	15,000

Southwestern Electric Power Company
Docket No. 19-008-U
Test Year Ending December 31, 2018

CUSTOMER GROUP	RATE CODE	VOLTAGE LEVEL	12-MONTH CUSTOMER COUNT ADJUSTED SCHEDULE E-11.2 RESULTS	12-MONTH CUSTOMER COUNT H-2 SCHEDULE CUSTOMER	KWH ADJUSTED SCHEDULE E-11.2 RESULTS	KWH H-2 SCHEDULE KWH UNITS	BILLING KW ADJUSTED SCHEDULE E-11.2 RESULTS	BILLING KW H-2 SCHEDULE KW UNITS	PRESENT RATE SCHEDULE REVENUE	PROPOSED RATE SCHEDULE REVENUE	RATE SCHEDULE CHANGE	TARGET RATE SCHEDULE CHANGE	RATE DESIGN DIFFERENCE	RATE CHANGE
RESDIENTIAL	15/38/62	SEC	1,051,109	1,051,108	951,051,881	951,051,881	n/a	n/a	45,329,688	72,096,294	26,766,606	26,766,988	(382)	59.0%
RESIDENTIAL ELECTRIC HEATING APPLIANCE	22/39	SEC	166,951	166,951	206,809,318	206,809,316	n/a	n/a	8,315,373	13,225,247	4,909,874	4,910,193	(319)	59.0%
TOTAL RESIDENTIAL			1,218,059	1,218,059	1,157,861,199	1,157,861,197			53,645,062	85,321,541	31,676,480	31,677,180	(701)	59.0%
GENERAL SERVICE	50/200/202/220 222/282/204	SEC	193,327	193,327	381,304,270	381,304,270	993,136	993,136	15,799,494	23,295,012	7,495,518	7,493,986	1,532	47.4%
LIGHTING & POWER SECONDARY	60/240/243/292	SEC	19,396	19,395	1,095,709,221	1,095,709,221	3,082,841	3,082,841	30,742,086	51,719,681	20,977,595	20,975,562	2,033	68.2%
LIGHTING & POWER PRIMARY	66/246/249/ 250/251/336	PRI	649	648	575,305,810	575,305,810	1,349,506	1,349,506	13,068,865	21,722,626	8,653,761	8,601,373	52,388	66.2%
LARGE LIGHTING & POWER PRIMARY	319/346	PRI	24	24	174,504,451	174,504,451	344,769	344,769	3,731,299	6,132,635	2,401,335	2,455,783	(54,448)	64.4%
TOTAL LIGHTING & POWER PRIMARY			673	672	749,810,261	749,810,261	1,694,275	1,694,275	16,800,165	27,855,261	11,055,096	11,057,156	(2,060)	65.8%
LIGHTING & POWER TOU SECONDARY	223	SEC	24	24	6,267,577	6,267,577	32,677	32,677	248,498	553,854	305,357	305,399	(42)	122.9%
LIGHTING & POWER TOU PRIMARY	225	PRI	12	12	16,831,547	16,831,547	32,422	32,422	187,060	416,955	229,895	229,893	2	122.9%
TOTAL LIGHTING & POWER TOU			36	36	23,099,124	23,099,124	65,099	65,099	435,558	970,809	535,252	535,292	(40)	122.9%
INDUSTRIAL PULP & PAPER MILL	326	69 KV TRANS	12	12	243,588,954	243,588,954	466,021	466,021	4,254,656	6,249,063	1,994,407	1,995,143	(735)	46.9%
LARGE LIGHTING & POWER 69 KV	342	69 KV TRANS	12	12	156,167,361	156,167,361	262,644	262,644	2,195,911	3,816,911	1,621,000	1,620,986	14	73.8%
MUNICIPAL PUMPING	550/540/549	SEC	3,258	3,258	15,640,389	15,640,389	n/a	n/a	509,010	699,531	190,521	190,902	(381)	37.4%
MUNICIPAL SERVICE	544/545	SEC	5,791	5,791	5,713,097	5,713,097	n/a	n/a	244,646	336,558	91,912	91,754	158	37.6%
TOTAL MUNICIPAL			9,049	9,049	21,353,486	21,353,486			753,656	1,036,089	282,432	282,656	(224)	37.5%
PRIVATE, OUTDOOR, AREA	090-140	SEC	197,616	197,616	26,642,383	26,642,383	n/a	n/a	3,169,707	2,397,522	(772,185)	(772,629)	444	-24.4%
MUNICIPAL STREET & PRKWY	528-531	SEC	170,868	170,868	11,585,980	11,585,980	n/a	n/a	1,388,614	1,049,900	(338,714)	(338,480)	(234)	-24.4%
TOTAL LIGHTING			368,484	368,484	38,228,362	38,228,362			4,558,322	3,447,422	(1,110,899)	(1,111,109)	210	-24.4%
TOTAL FIRM RETAIL			1,809,048	1,809,045	3,867,122,238	3,867,122,236	6,564,015	6,564,015	129,184,908	203,711,789	74,526,881	74,526,851	29	57.7%

NOTE 1: ANY SLIGHT E-11.2 AND H-2 DIFFERENCES ARE DUE TO ROUNDING TO WHOLE CUSTOMER AND KWH UNITS
NOTE 2: ONLY KW USED FOR BILLING IS INCLUDED IN H-2
NOTE 3: LIGHTING FIXTURE COUNTS ARE REPRESENTED IN THE 12-MONTH CUSTOMER COUNT COLUMN

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**									
2	*Residential Service 015*									
3	*May - September*									
4	*Customer Charge*	*437,518*	*$ 7.75*	*$ 3,390,765*	*7.3%*	*$10.00*	*$ 4,375,180*	*5.9%*	*$ 984,416*	*29.0%*
5	*0 - 1,500 kWh*	*383,069,248*	*$ 0.0442*	*$ 16,931,661*	*36.5%*	*$ 0.0702*	*$ 26,891,461*	*36.4%*	*$ 9,959,800*	*58.8%*
6	*all kWh over 1,500*	*61,185,571*	*$ 0.0534*	*$ 3,267,309*	*7.0%*	*$ 0.0919*	*$ 5,622,954*	*7.6%*	*$ 2,355,644*	*72.1%*
7										
8	*October - April*									
9	*Customer Charge*	*612,526*	*$ 7.75*	*$ 4,747,077*	*10.2%*	*$10.00*	*$ 6,125,260*	*8.3%*	*$ 1,378,184*	*29.0%*
10	*all kWh*	*505,990,446*	*$ 0.0358*	*$ 18,114,458*	*39.0%*	*$ 0.0610*	*$ 30,865,417*	*41.8%*	*$ 12,750,959*	*70.4%*
11										
12	*Total Customer Applications*	*1,050,044*								
13	*Total kWh*	*950,245,265*								
14										
15	*Subtotal Residential Service 015 Revenues*			*$ 46,451,269*	*100.0%*		*$ 73,880,272*	*100.0%*	*$ 27,429,003*	*59.0%*
16	*Book-to-Bill Ratio*			*0.975*			*0.975*			
17	*Total Residential Service 015 Base Rate Revenues*			*$ 45,290,089*			*$ 72,033,427*			
18	*Residential Service 015 Revenues as a % of Total Class Revenues (A)*			*$ 45,290,089*	*50.2%*		*$ 72,033,427*	*64.3%*		
19										
20	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*		
21	*Energy Cost Recovery*	*950,245,265*	*$ 0.032419*	*$ 30,806,001*	*34.2%*	*$ 0.032419*	*$ 30,806,001*	*27.5%*	*$ -*	*0.0%*
22	*Energy Efficiency Cost Rate*	*950,245,265*	*$ 0.007620*	*$ 7,240,869*	*8.0%*	*$ 0.004930*	*$ 4,684,709*	*4.2%*	*$ (2,556,160)*	*-35.3%*
23	*Alternate Generation Recovery*	*950,245,265*	*$ 0.002710*	*$ 2,575,165*	*2.9%*	*$ -*	*$ -*	*0.0%*	*$ (2,575,165)*	*-100.0%*
24	*Environmental Compliance Surcharge*	*950,245,265*	*$ 0.004490*	*$ 4,266,601*	*4.7%*	*$ -*	*$ -*	*0.0%*	*$ (4,266,601)*	*-100.0%*
25	*Distribution Relability Request*	*950,245,265*	*$ -*	*$ -*		*$ 0.004713*	*$ 4,478,506*	*4.0%*	*$ 4,478,506*	*#DIV/0!*
26	*Federal Tax Cut Adjustment*	*$45,290,089*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
27										
28	*Subtotal Rate Schedule Riders*			*$ 44,888,636*	*49.8%*		*$ 39,969,216*	*35.7%*	*$ (4,919,420)*	*-11.0%*
29										
30	*Total Residential Service 015 Revenues (rate schedule + riders)*			*$ 90,178,725*	*100.0%*		*$ 112,002,643*	*100.0%*	*$ 21,823,918*	*24.2%*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**									
2	*Residential Service 038 - Multiple Dwelling*									
3	*May - September*									
4	*Customer Charge*	*176*	*$ 7.75*	*$ 1,364*	*8.1%*	*$10.00*	*$ 1,760*	*6.6%*	*$ 396*	*29.0%*
5	*0 - 1,500 kWh*	*119,922*	*$ 0.0442*	*$ 5,301*	*31.5%*	*$ 0.0702*	*$ 8,419*	*31.6%*	*$ 3,118*	*58.8%*
6	*all kWh over 1,500*	*411*	*$ 0.0534*	*$ 22*	*0.1%*	*$ 0.0919*	*$ 38*	*0.1%*	*$ 16*	*72.1%*
7										
8	*October - April*									
9	*Customer Charge*	*247*	*$ 7.75*	*$ 1,914*	*11.4%*	*$10.00*	*$ 2,470*	*9.3%*	*$ 556*	*29.0%*
10	*all kWh*	*229,197*	*$ 0.0358*	*$ 8,205*	*48.8%*	*$ 0.0610*	*$ 13,981*	*52.4%*	*$ 5,776*	*70.4%*
11										
12	*Total Customer Applications*	*423*								
13	*Total kWh*	*349,530*								
14										
15	*Subtotal Residential Service 038 Revenues*			*$ 16,806*	*100.0%*		*$ 26,667*	*100.0%*	*$ 9,861*	*58.7%*
16	*Book-to-Bill Ratio*			*$ 1*			*1.000*			
17	*Total Residential Service 038 Base Rate Revenues*			*$ 16,807*			*$ 26,668*			
18	*Residential Service 038 Revenues as a % of Total Class Revenues (A)*			*$ 16,807*	*50.4%*		*$ 26,668*	*64.5%*		
19										
20	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*		
21	*Energy Cost Recovery*	*349,530*	*$ 0.032419*	*$ 11,331*	*34.0%*	*$ 0.032419*	*$ 11,331*	*27.4%*	*$ -*	*0.0%*
22	*Energy Efficiency Cost Rate*	*349,530*	*$ 0.007620*	*$ 2,663*	*8.0%*	*$ 0.004930*	*$ 1,723*	*4.2%*	*$ (940)*	*-35.3%*
23	*Alternate Generation Recovery*	*349,530*	*$ 0.002710*	*$ 947*	*2.8%*	*$ -*	*$ -*	*0.0%*	*$ (947)*	*-100.0%*
24	*Environmental Compliance Surcharge*	*349,530*	*$ 0.004490*	*$ 1,569*	*4.7%*	*$ -*	*$ -*	*0.0%*	*$ (1,569)*	*-100.0%*
25	*Distribution Relability Request*	*349,530*	*$ -*	*$ -*	*0.0%*	*$ 0.004713*	*$ 1,647*	*4.0%*	*$ 1,647*	*#DIV/0!*
26	*Federal Tax Cut Adjustment*	*$16,807*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
27	*Subtotal Rate Schedule Riders*			*$ 16,511*	*49.6%*		*$ 14,702*	*35.5%*	*$ (1,810)*	*-11.0%*
28										
29	*Total Residential Service 038 Revenues (rate schedule + riders)*			*$ 33,318*	*100.0%*		*$ 41,370*	*100.0%*	*$ 8,052*	*24.2%*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**									
2	*Residential Service 062 - Net Metering*									
3	*May - September*									
4	*Customer Charge*	*267*	*$ 7.75*	*$ 2,069*	*8.8%*	*$10.00*	*$ 2,670*	*7.1%*	*$ 601*	*29.0%*
5	*0 - 1,500 kWh*	*143,106*	*$ 0.0442*	*$ 6,325*	*26.8%*	*$ 0.0702*	*$ 10,046*	*26.8%*	*$ 3,721*	*58.8%*
6	*all kWh over 1,500*	*60,657*	*$ 0.0534*	*$ 3,239*	*13.7%*	*$ 0.0919*	*$ 5,574*	*14.9%*	*$ 2,335*	*72.1%*
7										
8	*October - April*									
9	*Customer Charge*	*374*	*$ 7.75*	*$ 2,899*	*12.3%*	*$10.00*	*$ 3,740*	*10.0%*	*$ 842*	*29.0%*
10	*all kWh*	*253,323*	*$ 0.0358*	*$ 9,069*	*38.4%*	*$ 0.0610*	*$ 15,453*	*41.2%*	*$ 6,384*	*70.4%*
11										
12	*Total Customer Applications*	*641*								
13	*Total kWh*	*457,086*								
14										
15	*Subtotal Residential Service 062 Revenues*			*$ 23,601*	*100.0%*		*$ 37,483*	*100.0%*	*$ 13,882*	*58.8%*
16	*Book-to-Bill Ratio*			*0.966*			*0.966*			
17	*Total Residential Service 062 Base Rate Revenues*			*$ 22,793*			*$ 36,199*			
18	*Residential Service 062 Revenues as a % of Total Class Revenues (A)*			*$ 22,793*	*51.4%*		*$ 36,199*	*65.3%*		
19										
20	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*		
21	*Energy Cost Recovery*	*457,086*	*$ 0.032419*	*$ 14,818*	*33.4%*	*$ 0.032419*	*$ 14,818*	*26.7%*	*$ -*	*0.0%*
22	*Energy Efficiency Cost Rate*	*457,086*	*$ 0.007620*	*$ 3,483*	*7.8%*	*$ 0.004930*	*$ 2,253*	*4.1%*	*$ (1,230)*	*-35.3%*
23	*Alternate Generation Recovery*	*457,086*	*$ 0.002710*	*$ 1,239*	*2.8%*	*$ -*	*$ -*	*0.0%*	*$ (1,239)*	*-100.0%*
24	*Environmental Compliance Surcharge*	*457,086*	*$ 0.004490*	*$ 2,052*	*4.6%*	*$ -*	*$ -*	*0.0%*	*$ (2,052)*	*-100.0%*
25	*Distribution Relability Request*	*457,086*	*$ -*	*$ -*	*0.0%*	*$ 0.004713*	*$ 2,154*	*3.9%*	*$ 2,154*	*#DIV/0!*
26	*Federal Tax Cut Adjustment*	*$22,793*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
27	*Subtotal Rate Schedule Riders*			*$ 21,592*	*48.6%*		*$ 19,226*	*34.7%*	*$ (2,366)*	*-11.0%*
28										
29	*Total Residential Service 062 Revenues (rate schedule + riders)*			*$ 44,385*	*100.0%*		*$ 55,425*	*100.0%*	*$ 11,040*	*24.9%*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Southwestern Electric Power Company
Docket No. 19-008-U
Test Year Ending December 31, 2018

Schedule: H-2
Title: Analysis of Revenue by Detailed Rate Schedule

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**									
2	*Residential Service 022 - Electric Heating Appliance*									
3	*May - September*									
4	*Customer Charge*	*69,376*	$ 7.75	$ 537,666	6.4%	$10.00	$ 693,763	5.2%	$ 156,097	29.0%
5	*0 - 1,500 kWh*	*67,264,359*	$ 0.0442	$ 2,973,085	35.2%	$ 0.0702	$ 4,721,958	35.1%	$ 1,748,873	58.8%
6	*all kWh over 1,500*	*14,634,375*	$ 0.0534	$ 781,476	9.2%	$ 0.0919	$ 1,344,899	10.0%	$ 563,423	72.1%
7										
8	*October - April*									
9	*Customer Charge*	*97,127*	$ 7.75	$ 752,733	8.9%	$10.00	$ 971,268	7.2%	$ 218,535	29.0%
10	*0 - 500 kWh*	*43,030,905*	$ 0.0358	$ 1,540,506	18.2%	$ 0.0610	$ 2,624,885	19.5%	$ 1,084,379	70.4%
11	*all kWh over 500*	*81,038,743*	$ 0.0230	$ 1,863,891	22.1%	$ 0.0380	$ 3,081,093	22.9%	$ 1,217,202	65.3%
12										
13	*Total Customer Applications*	*166,503*								
14	*Total kWh*	*205,968,382*								
15										
16	*Subtotal Residential Service 022 Revenues*			$ 8,449,356	100.0%		$ 13,437,866	100.0%	$ 4,988,509	59.0%
17	*Book-to-Bill Ratio*			0.981			0.981			
18	*Total Residential Service 022 Base Rate Revenues*			$ 8,285,128			$ 13,176,677			
19	*Residential Service 022 Revenues as a % of Total Class Revenues (A)*			$ 8,285,128	46.0%		$ 13,176,677	60.3%		
20										
21	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*		
22	*Energy Cost Recovery*	*205,968,382*	$ 0.032419	$ 6,677,289	37.1%	$ 0.032419	$ 6,677,289	30.6%	$ -	0.0%
23	*Energy Efficiency Cost Rate*	*205,968,382*	$ 0.007620	$ 1,569,479	8.7%	$ 0.004930	$ 1,015,424	4.6%	$ (554,055)	-35.3%
24	*Alternate Generation Recovery*	*205,968,382*	$ 0.002710	$ 558,174	3.1%	$ -	$ -	0.0%	$ (558,174)	-100.0%
25	*Environmental Compliance Surcharge*	*205,968,382*	$ 0.004490	$ 924,798	5.1%	$ -	$ -	0.0%	$ (924,798)	-100.0%
26	*Distribution Relability Request*	*205,968,382*	$ -	$ -	0.0%	$ 0.004713	$ 970,729	4.4%	$ 970,729	#DIV/0!
27	*Federal Tax Cut Adjustment*	*$8,285,128*	0.00%	$ -	0.0%	0.00%	$ -	0.0%	$ -	#DIV/0!
28	*Subtotal Rate Schedule Riders*			$ 9,729,740	54.0%		$ 8,663,442	39.7%	$ (1,066,298)	-11.0%
29										
30	*Total Residential Service 022 Revenues (rate schedule + riders)*			$ 18,014,869	100.0%		$ 21,840,119	100.0%	$ 3,825,250	21.2%

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES					PROPOSED RATES					CHANGE		
(1) LINE NO.	(2) RATE COMPONENT DESCRIPTION	(3) CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	(4) RATE $		(5) REVENUE $	(6) % OF REVENUES**		(7) RATE $		(8) REVENUE $	(9) % OF REVENUES**		(10) TOTAL REVENUE	(11) %
1	**RATE SCHEDULE DESCRIPTION**													
2	*Residential Service 039 - Electric Heating Appliance Multiple Dwelling*													
3	*May - September*													
4	*Customer Charge*	*186*	$	7.75	$	1,445	4.6%		$10.00	$	1,865	3.7%	$	420	29.0%
5	*0 - 1,500 kWh*	*233,724*	$	0.0442	$	10,331	33.1%	$	0.0702	$	16,407	32.7%	$	6,077	58.8%
6	*all kWh over 1,500*	*61,044*	$	0.0534	$	3,260	10.4%	$	0.0919	$	5,610	11.2%	$	2,350	72.1%
7															
8	*October - April*														
9	*Customer Charge*	*261*	$	7.75	$	2,023	6.5%		$10.00	$	2,610	5.2%	$	587	29.0%
10	*0 - 500 kWh*	*127,342*	$	0.0358	$	4,559	14.6%	$	0.0610	$	7,768	15.5%	$	3,209	70.4%
11	*all kWh over 500*	*418,824*	$	0.0230	$	9,633	30.8%	$	0.0380	$	15,924	31.7%	$	6,291	65.3%
12															
13	*Total Customer Applications*	*447*													
14	*Total kWh*	*840,934*													
15															
16	*Subtotal Residential Service 039 Revenues*				$	31,250	100.0%			$	50,184	100.0%	$	18,934	60.6%
17	*Book-to-Bill Ratio*					0.968					0.968				
18	*Total Residential Service 039 Base Rate Revenues*				$	30,245				$	48,570				
19	*Residential Service 039 Revenues as a % of Total Class Revenues (A)*				$	30,245	43.2%			$	48,570	57.9%			
20															
21	*Riders & Requests - Adjusted Test Year*	*ljusted TY Unit*	*Present Factor*		*Present Factor $*		*% of Rider Revenues*	*Proposed Factor*		*Proposed Factor $*		*% of Rider Revenues*			
22	*Energy Cost Recovery*	*840,934*	$	0.032419	$	27,262	39.0%	$	0.032419	$	27,262	32.5%	$	-	0.0%
23	*Energy Efficiency Cost Rate*	*840,934*	$	0.007620	$	6,408	9.2%	$	0.004930	$	4,146	4.9%	$	(2,262)	-35.3%
24	*Alternate Generation Recovery*	*840,934*	$	0.002710	$	2,279	3.3%	$	-	$	-	0.0%	$	(2,279)	-100.0%
25	*Environmental Compliance Surcharge*	*840,934*	$	0.004490	$	3,776	5.4%	$	-	$	-	0.0%	$	(3,776)	-100.0%
26	*Distribution Relability Request*	*840,934*	$	-	$	-	0.0%	$	0.004713	$	3,963	4.7%	$	3,963	#DIV/0!
27	*Federal Tax Cut Adjustment*	*$30,245*		0.00%	$	-	0.0%		0.00%	$	-	0.0%	$	-	#DIV/0!
28	*Subtotal Rate Schedule Riders*				$	39,725	56.8%			$	35,371	42.1%	$	(4,354)	-11.0%
29															
30	*Total Residential Service 039 Revenues (rate schedule + riders)*				$	69,970	100.0%			$	83,941	100.0%	$	13,971	20.0%

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**									
2	*General Service 220*									
3	*May - September*									
4	*Customer Charge*	72,289	$ 8.60	$ 621,685	4.5%	$10.60	$ 766,263	3.7%	$ 144,578	23.3%
5	*all kWh*	156,041,520	$ 0.0307	$ 4,790,475	34.3%	$ 0.0456	$ 7,115,493	34.6%	$ 2,325,019	48.5%
6										
7	*October - April*									
8	*Customer Charge*	101,205	$ 8.60	$ 870,363	6.2%	$10.60	$ 1,072,773	5.2%	$ 202,410	23.3%
9	*all kWh*	166,378,268	$ 0.0252	$ 4,192,732	30.1%	$ 0.0373	$ 6,205,909	30.2%	$ 2,013,177	48.0%
10										
11	*Billing kW in excess of 6 kW*	826,557	$ 4.20	$ 3,471,540	24.9%	$6.51	$ 5,380,886	26.2%	$ 1,909,347	55.0%
12										
13										
14	*Total Customer Applications*	173,494								
15	*Total kWh*	322,419,788								
16										
17	*Subtotal General Service 220 Revenues*			$ 13,946,795	100.0%		$ 20,541,325	100.0%	$ 6,594,530	47.3%
18	*Book-to-Bill Ratio*			0.961			0.961			
19	*Total General Service 220 Base Rate Revenues*			$ 13,396,874			$ 19,731,383			
20	*General Service 220 Revenues as a % of Total Class Revenues (A)*			$ 13,396,874	47.6%		$ 19,731,383	60.4%		
21										
22	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*		
23	*Energy Cost Recovery*	322,419,788	$ 0.032419	$ 10,452,527	37.2%	$ 0.032419	$ 10,452,527	32.0%	$ -	0.0%
24	*Energy Efficiency Cost Rate (opt out adj)*	322,261,658	$ 0.006610	$ 2,130,150	7.6%	$ 0.004280	$ 1,379,280	4.2%	$ (750,870)	-35.2%
25	*Alternate Generation Recovery*	13,396,874	7.79%	$ 1,043,616	3.7%	0.00%	$ -	0.0%	$ (1,043,616)	-100.0%
26	*Environmental Compliance Surcharge*	322,419,788	$ 0.003420	$ 1,102,676	3.9%	$ -	$ -	0.0%	$ (1,102,676)	-100.0%
27	*Distribution Relability Request*	322,419,788	$ -	$ -	0.0%	$ 0.003375	$ 1,088,167	3.3%	$ 1,088,167	#DIV/0!
28	*Federal Tax Cut Adjustment*	$13,396,874	0.00%	$ -	0.0%	0.00%	$ -	0.0%	$ -	#DIV/0!
29	*Subtotal Rate Schedule Riders*			$ 14,728,969	52.4%		$ 12,919,974	39.6%	$ (1,808,995)	-12.3%
30										
31	*Total General Service 220 Revenues (rate schedule + riders)*			$ 28,125,843	100.0%		$ 32,651,356	100.0%	$ 4,525,514	16.1%

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**									
2	*General Service 222 W/C2 Rider*									
3	*May - September*									
4	*Customer Charge*	*6,193*	*$ 8.60*	*$ 53,260*	*2.9%*	*$10.60*	*$ 65,646*	*2.4%*	*$ 12,386*	*23.3%*
5	*all kWh*	*18,393,738*	*$ 0.0307*	*$ 564,688*	*30.2%*	*$ 0.0456*	*$ 838,754*	*30.3%*	*$ 274,067*	*48.5%*
6										
7	*October - April*									
8	*Customer Charge*	*8,670*	*$ 8.60*	*$ 74,562*	*4.0%*	*$10.60*	*$ 91,902*	*3.3%*	*$ 17,340*	*23.3%*
9	*all kWh*	*26,116,871*	*$ 0.0252*	*$ 658,145*	*35.2%*	*$ 0.0373*	*$ 974,159*	*35.2%*	*$ 316,014*	*48.0%*
10										
11	*Billing kW in excess of 6 kW*	*122,960*	*$ 4.20*	*$ 516,432*	*27.7%*	*$6.51*	*$ 800,469*	*28.9%*	*$ 284,038*	*55.0%*
12										
13										
14	*Total Customer Applications*	*14,863*								
15	*Total kWh*	*44,510,608*								
16										
17	*Subtotal General Service 222 Revenues*			*$ 1,867,087*	*100.0%*		*$ 2,770,931*	*100.0%*	*$ 903,844*	*48.4%*
18	*Book-to-Bill Ratio*			*0.969*			*0.969*			
19	*Total General Service 222 Base Rate Revenues*			*$ 1,809,105*			*$ 2,684,880*			
20	*General Service 222 Revenues as a % of Total Class Revenues (A)*			*$ 1,809,105*	*47.1%*		*$ 2,684,880*	*60.1%*		
21										
22	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*		
23	*Energy Cost Recovery*	*44,510,608*	*$ 0.032419*	*$ 1,442,989*	*37.6%*	*$ 0.032419*	*$ 1,442,989*	*32.3%*	*$ -*	*0.0%*
24	*Energy Efficiency Cost Rate*	*44,510,608*	*$ 0.006610*	*$ 294,215*	*7.7%*	*$ 0.004280*	*$ 190,505*	*4.3%*	*$ (103,710)*	*-35.2%*
25	*Alternate Generation Recovery*	*1,809,105*	*7.79%*	*$ 140,929*	*3.7%*	*0.00%*	*$ -*	*0.0%*	*$ (140,929)*	*-100.0%*
26	*Environmental Compliance Surcharge*	*44,510,608*	*$ 0.003420*	*$ 152,226*	*4.0%*	*$ -*	*$ -*	*0.0%*	*$ (152,226)*	*-100.0%*
27	*Distribution Relability Request*	*44,510,608*	*$ -*	*$ -*	*0.0%*	*$ 0.003375*	*$ 150,223*	*3.4%*	*$ 150,223*	*#DIV/0!*
28	*Federal Tax Cut Adjustment*	*$1,809,105*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
29	*Subtotal Rate Schedule Riders*			*$ 2,030,360*	*52.9%*		*$ 1,783,718*	*39.9%*	*$ (246,642)*	*-12.1%*
30										
31	*Total General Service 222 Revenues (rate schedule + riders)*			*$ 3,839,465*	*100.0%*		*$ 4,468,598*	*100.0%*	*$ 629,134*	*16.4%*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**									
2	*General Service 200 W/C2 Rider*									
3	*May - September*									
4	*Customer Charge*	*1,433*	*$ 8.60*	*$ 12,324*	*2.6%*	*$10.60*	*$ 15,190*	*2.1%*	*$ 2,866*	*23.3%*
5	*all kWh*	*4,223,859*	*$ 0.0307*	*$ 129,672*	*27.1%*	*$ 0.0456*	*$ 192,608*	*27.0%*	*$ 62,936*	*48.5%*
6										
7	*October - April*									
8	*Customer Charge*	*2,006*	*$ 8.60*	*$ 17,252*	*3.6%*	*$10.60*	*$ 21,264*	*3.0%*	*$ 4,012*	*23.3%*
9	*all kWh*	*5,797,835*	*$ 0.0252*	*$ 146,105*	*30.5%*	*$ 0.0373*	*$ 216,259*	*30.3%*	*$ 70,154*	*48.0%*
10										
11	*Billing kW in excess of 6 kW*	*41,376*	*$ 4.20*	*$ 173,778*	*36.3%*	*$6.51*	*$ 269,356*	*37.7%*	*$ 95,578*	*55.0%*
12										
13										
14	*Total Customer Applications*	*3,439*								
15	*Total kWh*	*10,021,693*								
16										
17	*Subtotal General Service 200 Revenues*			*$ 479,131*	*100.0%*		*$ 714,676*	*100.0%*	*$ 235,545*	*49.2%*
18	*Book-to-Bill Ratio*			*0.965*			*0.965*			
19	*Total General Service 200 Base Rate Revenues*			*$ 462,601*			*$ 690,019*			
20	*General Service 200 Revenues as a % of Total Class Revenues (A)*			*$ 462,601*	*50.1%*		*$ 690,019*	*63.2%*		
21										
22	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*		
23	*Energy Cost Recovery*	*10,021,693*	*$ 0.032419*	*$ 324,893*	*35.2%*	*$ 0.032419*	*$ 324,893*	*29.8%*	*$ -*	*0.0%*
24	*Energy Efficiency Cost Rate*	*10,021,693*	*$ 0.006610*	*$ 66,243*	*7.2%*	*$ 0.004280*	*$ 42,893*	*3.9%*	*$ (23,351)*	*-35.2%*
25	*Alternate Generation Recovery*	*462,601*	*7.79%*	*$ 36,037*	*3.9%*	*0.00%*	*$ -*	*0.0%*	*$ (36,037)*	*-100.0%*
26	*Environmental Compliance Surcharge*	*10,021,693*	*$ 0.003420*	*$ 34,274*	*3.7%*	*$ -*	*$ -*	*0.0%*	*$ (34,274)*	*-100.0%*
27	*Distribution Reliability Request*	*10,021,693*	*$ -*	*$ -*	*0.0%*	*$ 0.003375*	*$ 33,823*	*3.1%*	*$ 33,823*	*#DIV/0!*
28	*Federal Tax Cut Adjustment*	*$462,601*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
29	*Subtotal Rate Schedule Riders*			*$ 461,447*	*49.9%*		*$ 401,609*	*36.8%*	*$ (59,838)*	*-13.0%*
30										
31	*Total General Service 200 Revenues (rate schedule + riders)*			*$ 924,048*	*100.0%*		*$ 1,091,629*	*100.0%*	*$ 167,581*	*18.1%*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**									
2	*General Service 202 - Unmetered*									
3	*May - September*									
4	*Customer Charge*	*40*	*$ 8.60*	*$ 344*	*21.6%*	*$10.60*	*$ 424*	*19.6%*	*$ 80*	*23.3%*
5	*all kWh*	*11,722*	*$ 0.0307*	*$ 360*	*22.6%*	*$ 0.0456*	*$ 535*	*24.8%*	*$ 175*	*48.5%*
6										
7	*October - April*									
8	*Customer Charge*	*56*	*$ 8.60*	*$ 482*	*30.2%*	*$10.60*	*$ 594*	*27.5%*	*$ 112*	*23.3%*
9	*all kWh*	*16,242*	*$ 0.0252*	*$ 409*	*25.7%*	*$ 0.0373*	*$ 606*	*28.1%*	*$ 197*	*48.0%*
10										
11	*Billing kW in excess of 6 kW*	*0*	*$ 4.20*	*$ -*	*0.0%*	*$6.51*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
12										
13										
14	*Total Customer Applications*	*96*								
15	*Total kWh*	*27,964*								
16										
17	*Subtotal General Service 202 Revenues*			*$ 1,595*	*100.0%*		*$ 2,158*	*100.0%*	*$ 563*	*35.3%*
18	*Book-to-Bill Ratio*			*0.977*			*0.977*			
19	*Total General Service 202 Base Rate Revenues*			*$ 1,559*			*$ 2,109*			
20	*General Service 202 Revenues as a % of Total Class Revenues (A)*			*$ 1,559*	*54.4%*		*$ 2,109*	*65.3%*		
21										
22	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*		
23	*Energy Cost Recovery*	*27,964*	*$ 0.032419*	*$ 907*	*31.6%*	*$ 0.032419*	*$ 907*	*28.1%*	*$ -*	*0.0%*
24	*Energy Efficiency Cost Rate*	*27,964*	*$ 0.006610*	*$ 185*	*6.4%*	*$ 0.004280*	*$ 120*	*3.7%*	*$ (65)*	*-35.2%*
25	*Alternate Generation Recovery*	*1,559*	*7.79%*	*$ 121*	*4.2%*	*0.00%*	*$ -*	*0.0%*	*$ (121)*	*-100.0%*
26	*Environmental Compliance Surcharge*	*27,964*	*$ 0.003420*	*$ 96*	*3.3%*	*$ -*	*$ -*	*0.0%*	*$ (96)*	*-100.0%*
27	*Distribution Relability Request*	*27,964*	*$ -*	*$ -*	*0.0%*	*$ 0.003375*	*$ 94*	*2.9%*	*$ 94*	*#DIV/0!*
28	*Federal Tax Cut Adjustment*	*$1,559*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
29	*Subtotal Rate Schedule Riders*			*$ 1,308*	*45.6%*		*$ 1,121*	*34.7%*	*$ (188)*	*-14.4%*
30										
31	*Total General Service 202 Revenues (rate schedule + riders)*			*$ 2,867*	*100.0%*		*$ 3,230*	*100.0%*	*$ 363*	*12.6%*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1) LINE NO.	(2) RATE COMPONENT DESCRIPTION	(3) CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	(4) RATE $	(5) REVENUE $	(6) % OF REVENUES**	(7) RATE $	(8) REVENUE $	(9) % OF REVENUES**	(10) TOTAL REVENUE	(11) %
1	**RATE SCHEDULE DESCRIPTION**									
2	*General Service 282 - Net Metering*									
3	*May - September*									
4	*Customer Charge*	*45*	*$ 8.60*	*$ 387*	*2.4%*	*$10.60*	*$ 477*	*2.0%*	*$ 90*	*23.3%*
5	*all kWh*	*152,380*	*$ 0.0307*	*$ 4,678*	*28.9%*	*$ 0.0456*	*$ 6,949*	*28.7%*	*$ 2,270*	*48.5%*
6										
7	*October - April*									
8	*Customer Charge*	*63*	*$ 8.60*	*$ 542*	*3.3%*	*$10.60*	*$ 668*	*2.8%*	*$ 126*	*23.3%*
9	*all kWh*	*179,421*	*$ 0.0252*	*$ 4,521*	*27.9%*	*$ 0.0373*	*$ 6,692*	*27.7%*	*$ 2,171*	*48.0%*
10										
11	*Billing kW in excess of 6 kW*	*1,444*	*$ 4.20*	*$ 6,065*	*37.5%*	*$6.51*	*$ 9,401*	*38.9%*	*$ 3,336*	*55.0%*
12										
13										
14	*Total Customer Applications*	*108*								
15	*Total kWh*	*331,801*								
16										
17	*Subtotal General Service 282 Revenues*			*$ 16,193*	*100.0%*		*$ 24,187*	*100.0%*	*$ 7,993*	*49.4%*
18	*Book-to-Bill Ratio*			*0.923*			*0.923*			
19	*Total General Service 282 Base Rate Revenues*			*$ 14,941*			*$ 22,316*			
20	*General Service 282 Revenues as a % of Total Class Revenues (A)*			*$ 14,941*	*49.5%*		*$ 22,316*	*62.7%*		
21										
22	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*		
23	*Energy Cost Recovery*	*331,801*	*$ 0.032419*	*$ 10,757*	*35.6%*	*$ 0.032419*	*$ 10,757*	*30.2%*	*$ -*	*0.0%*
24	*Energy Efficiency Cost Rate*	*331,801*	*$ 0.006610*	*$ 2,193*	*7.3%*	*$ 0.004280*	*$ 1,420*	*4.0%*	*$ (773)*	*-35.2%*
25	*Alternate Generation Recovery*	*14,941*	*7.79%*	*$ 1,164*	*3.9%*	*0.00%*	*$ -*	*0.0%*	*$ (1,164)*	*-100.0%*
26	*Environmental Compliance Surcharge*	*331,801*	*$ 0.003420*	*$ 1,135*	*3.8%*	*$ -*	*$ -*	*0.0%*	*$ (1,135)*	*-100.0%*
27	*Distribution Relability Request*	*331,801*	*$ -*	*$ -*	*0.0%*	*$ 0.003375*	*$ 1,120*	*3.1%*	*$ 1,120*	*#DIV/0!*
28	*Federal Tax Cut Adjustment*	*$14,941*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
29	*Subtotal Rate Schedule Riders*			*$ 15,249*	*50.5%*		*$ 13,297*	*37.3%*	*$ (1,952)*	*-12.8%*
30										
31	*Total General Service 282 Revenues (rate schedule + riders)*			*$ 30,189*	*100.0%*		*$ 35,613*	*100.0%*	*$ 5,423*	*18.0%*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**									
2	*General Service 050 - Master Metered*									
3	*May - September*									
4	*Customer Charge*	25	$ 8.60	$ 215	1.4%	$10.60	$ 265	1.2%	$ 50	23.3%
5	*all kWh*	179,731	$ 0.0307	$ 5,518	35.7%	$ 0.0456	$ 8,196	35.6%	$ 2,678	48.5%
6										
7	*October - April*									
8	*Customer Charge*	35	$ 8.60	$ 301	1.9%	$10.60	$ 371	1.6%	$ 70	23.3%
9	*all kWh*	241,502	$ 0.0252	$ 6,086	39.3%	$ 0.0373	$ 9,008	39.1%	$ 2,922	48.0%
10										
11	*Billing kW in excess of 6 kW*	799	$ 4.20	$ 3,355	21.7%	$6.51	$ 5,200	22.6%	$ 1,845	55.0%
12										
13										
14	*Total Customer Applications*	60								
15	*Total kWh*	421,233								
16										
17	*Subtotal General Service 050 Revenues*			$ 15,474	100.0%		$ 23,040	100.0%	$ 7,565	48.9%
18	*Book-to-Bill Ratio*			0.962			0.962			
19	*Total General Service 050 Base Rate Revenues*			$ 14,879			$ 22,154			
20	*General Service 050 Revenues as a % of Total Class Revenues (A)*			$ 14,879	43.9%		$ 22,154	56.8%		
21										
22	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*		
23	*Energy Cost Recovery*	421,233	$ 0.032419	$ 13,656	40.3%	$ 0.032419	$ 13,656	35.0%	$ -	0.0%
24	*Energy Efficiency Cost Rate*	421,233	$ 0.006610	$ 2,784	8.2%	$ 0.004280	$ 1,803	4.6%	$ (981)	-35.2%
25	*Alternate Generation Recovery*	14,879	7.79%	$ 1,159	3.4%	0.00%	$ -	0.0%	$ (1,159)	-100.0%
26	*Environmental Compliance Surcharge*	421,233	$ 0.003420	$ 1,441	4.2%	$ -	$ -	0.0%	$ (1,441)	-100.0%
27	*Distribution Relability Request*	421,233	$ -	$ -	0.0%	$ 0.003375	$ 1,422	3.6%	$ 1,422	#DIV/0!
28	*Federal Tax Cut Adjustment*	$14,879	0.00%	$ -	0.0%	0.00%	$ -	0.0%	$ -	#DIV/0!
29	*Subtotal Rate Schedule Riders*			$ 19,040	56.1%		$ 16,881	43.2%	$ (2,160)	-11.3%
30										
31	*Total General Service 050 Revenues (rate schedule + riders)*			$ 33,919	100.0%		$ 39,034	100.0%	$ 5,115	15.1%

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**									
2	*Recreational Lighting 204*									
3	*May - September*									
4	*Customer Charge*	*528*	*$ 8.60*	*$ 4,541*	*4.4%*	*$10.60*	*$ 5,597*	*3.8%*	*$ 1,056*	*23.3%*
5	*all kWh*	*1,387,926*	*$ 0.0257*	*$ 35,670*	*34.7%*	*$ 0.0373*	*$ 51,770*	*35.3%*	*$ 16,100*	*45.1%*
6										
7	*October - April*									
8	*Customer Charge*	*739*	*$ 8.60*	*$ 6,355*	*6.2%*	*$10.60*	*$ 7,833*	*5.3%*	*$ 1,478*	*23.3%*
9	*all kWh*	*2,183,256*	*$ 0.0257*	*$ 56,110*	*54.6%*	*$ 0.0373*	*$ 81,435*	*55.5%*	*$ 25,326*	*45.1%*
10										
11										
12										
13										
14	*Total Customer Applications*	*1,267*								
15	*Total kWh*	*3,571,182*								
16										
17	*Subtotal Recreational Lighting 204 Revenues*			*$ 102,676*	*100.0%*		*$ 146,635*	*100.0%*	*$ 43,960*	*42.8%*
18	*Book-to-Bill Ratio*			*0.969*			*0.969*			
19	*Total Receational Lighting Base Rate Revenues*			*$ 99,536*			*$ 142,151*			
20	*Recreational Lighting Revenues as a % of Total Class Revenues (A)*			*$ 99,536*	*38.4%*		*$ 142,151*	*49.8%*		
21										
22	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*		
23	*Energy Cost Recovery*	*3,571,182*	*$ 0.032419*	*$ 115,774*	*44.7%*	*$ 0.032419*	*$ 115,774*	*40.6%*	*$ -*	*0.0%*
24	*Energy Efficiency Cost Rate*	*3,571,182*	*$ 0.006610*	*$ 23,606*	*9.1%*	*$ 0.004280*	*$ 15,285*	*5.4%*	*$ (8,321)*	*-35.2%*
25	*Alternate Generation Recovery*	*99,536*	*7.79%*	*$ 7,754*	*3.0%*	*0.00%*	*$ -*	*0.0%*	*$ (7,754)*	*-100.0%*
26	*Environmental Compliance Surcharge*	*3,571,182*	*$ 0.003420*	*$ 12,213*	*4.7%*	*$ -*	*$ -*	*0.0%*	*$ (12,213)*	*-100.0%*
27	*Distribution Relability Request*	*3,571,182*	*$ -*	*$ -*	*0.0%*	*$ 0.003375*	*$ 12,053*	*4.2%*	*$ 12,053*	*#DIV/0!*
28	*Federal Tax Cut Adjustment*	*$99,536*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
29	*Subtotal Rate Schedule Riders*			*$ 159,347*	*61.6%*		*$ 143,112*	*50.2%*	*$ (16,235)*	*-10.2%*
30										
31	*Total Recreational Lighting Revenues (rate schedule + riders)*			*$ 258,883*	*100.0%*		*$ 285,263*	*100.0%*	*$ 26,380*	*10.2%*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**									
2	*Lighting & Power 240*									
3	*May - September*									
4	*Customer Charge*	*6,403*	*$ -*	*$ -*	*0.0%*	*$0.00*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
5	*all kWh*	*398,474,461*	*$ 0.0160*	*$ 6,375,591*	*25.0%*	*$ 0.0270*	*$ 10,758,810*	*25.1%*	*$ 4,383,219*	*68.8%*
6	*Billing kW*	*1,092,674*	*$ 7.55*	*$ 8,249,688*	*32.3%*	*$12.73*	*$ 13,909,739*	*32.4%*	*$ 5,660,051*	*68.6%*
7	*October - April*									
8	*Customer Charge*	*8,965*	*$ -*	*$ -*	*0.0%*	*$0.00*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
9	*all kWh*	*480,135,690*	*$ 0.0047*	*$ 2,256,638*	*8.8%*	*$ 0.0079*	*$ 3,793,072*	*8.8%*	*$ 1,536,434*	*68.1%*
10	*Billing kW*	*1,414,915*	*$ 6.10*	*$ 8,630,984*	*33.8%*	*$10.22*	*$ 14,460,435*	*33.7%*	*$ 5,829,451*	*67.5%*
11										
12										
13	*Total Customer Applications*	*15,368*								
14	*Total kWh*	*878,610,151*								
15	*Total kW*	*2,507,589*								
16	*Subtotal Lighting & Power 240 Revenues*			*$ 25,512,901*	*100.0%*		*$ 42,922,056*	*100.0%*	*$ 17,409,155*	*68.2%*
17	*Book-to-Bill Ratio*			*0.977*			*0.977*			
18	*Total Lighting & Power 240 Base Rate Revenues*			*$ 24,932,613*			*$ 41,945,799*			
19	*Lighting & Power 240 Revenues as a % of Total Class Revenues (A)*			*$ 24,932,613*	*39.6%*		*$ 41,945,799*	*55.0%*		
20										
21	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*		
22	*Energy Cost Recovery*	*878,610,151*	*$ 0.032419*	*$ 28,483,663*	*45.3%*	*$ 0.032419*	*$ 28,483,663*	*37.3%*	*$ -*	*0.0%*
23	*Energy Efficiency Cost Rate (opt out adj)*	*685,924,538*	*$ 0.006610*	*$ 4,533,961*	*7.2%*	*$ 0.004280*	*$ 2,935,757*	*3.8%*	*$ (1,598,204)*	*-35.2%*
24	*Alternate Generation Recovery*	*24,932,613*	*7.79%*	*$ 1,942,251*	*3.1%*	*0.00%*	*$ -*	*0.0%*	*$ (1,942,251)*	*-100.0%*
25	*Environmental Compliance Surcharge*	*878,610,151*	*$ 0.003420*	*$ 3,004,847*	*4.8%*	*$ -*	*$ -*	*0.0%*	*$ (3,004,847)*	*-100.0%*
26	*Distribution Relability Request*	*878,610,151*	*$ -*	*$ -*	*0.0%*	*$ 0.003375*	*$ 2,965,309*	*3.9%*	*$ 2,965,309*	*#DIV/0!*
27	*Federal Tax Cut Adjustment*	*$24,932,613*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
28	*Subtotal Rate Schedule Riders*			*$ 37,964,721*	*60.4%*		*$ 34,384,729*	*45.0%*	*$ (3,579,992)*	*-9.4%*
29										
30	*Total Lighting & Power 240 Revenues (rate schedule + riders)*			*$ 62,897,334*	*100.0%*		*$ 76,330,527*	*100.0%*	*$ 13,433,194*	*21.4%*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**									
2	*Lighting & Power 243 - W/C2 Rider*									
3	*May - September*									
4	*Customer Charge*	*1,648*	*$ -*	*$ -*	*0.0%*	*$0.00*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
5	*all kWh*	*93,192,351*	*$ 0.0160*	*$ 1,491,078*	*25.6%*	*$ 0.0270*	*$ 2,516,193*	*25.7%*	*$ 1,025,116*	*68.8%*
6	*Billing kW*	*243,949*	*$ 7.55*	*$ 1,841,813*	*31.6%*	*$12.73*	*$ 3,105,468*	*31.7%*	*$ 1,263,655*	*68.6%*
7	*October - April*									
8	*Customer Charge*	*2,307*	*$ -*	*$ -*	*0.0%*	*$0.00*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
9	*all kWh*	*118,721,282*	*$ 0.0047*	*$ 557,990*	*9.6%*	*$ 0.0079*	*$ 937,898*	*9.6%*	*$ 379,908*	*68.1%*
10	*Billing kW*	*317,342*	*$ 6.10*	*$ 1,935,789*	*33.2%*	*$10.22*	*$ 3,243,240*	*33.1%*	*$ 1,307,451*	*67.5%*
11										
12										
13	*Total Customer Applications*	*3,955*								
14	*Total kWh*	*211,913,632*								
15	*Total kW*	*561,291*								
16	*Subtotal Lighting & Power 243 Revenues*			*$ 5,826,670*	*100.0%*		*$ 9,802,800*	*100.0%*	*$ 3,976,130*	*68.2%*
17	*Book-to-Bill Ratio*			*0.973*			*0.973*			
18	*Total Lighting & Power 243 Base Rate Revenues*			*$ 5,668,775*			*$ 9,537,158*			
19	*Lighting & Power 243 Revenues as a % of Total Class Revenues (A)*			*$ 5,668,775*	*38.6%*		*$ 9,537,158*	*53.7%*		
20										
21	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*		
22	*Energy Cost Recovery*	*211,913,632*	*$ 0.032419*	*$ 6,870,028*	*46.8%*	*$ 0.032419*	*$ 6,870,028*	*38.7%*	*$ -*	*0.0%*
23	*Energy Efficiency Cost Rate (opt out adj)*	*149,153,192*	*$ 0.006610*	*$ 985,903*	*6.7%*	*$ 0.004280*	*$ 638,376*	*3.6%*	*$ (347,527)*	*-35.2%*
24	*Alternate Generation Recovery*	*5,668,775*	*7.79%*	*$ 441,598*	*3.0%*	*0.00%*	*$ -*	*0.0%*	*$ (441,598)*	*-100.0%*
25	*Environmental Compliance Surcharge*	*211,913,632*	*$ 0.003420*	*$ 724,745*	*4.9%*	*$ -*	*$ -*	*0.0%*	*$ (724,745)*	*-100.0%*
26	*Distribution Reliability Request*	*211,913,632*	*$ -*	*$ -*	*0.0%*	*$ 0.003375*	*$ 715,209*	*4.0%*	*$ 715,209*	*#DIV/0!*
27	*Federal Tax Cut Adjustment*	*$5,668,775*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
28	*Subtotal Rate Schedule Riders*			*$ 9,022,273*	*61.4%*		*$ 8,223,612*	*46.3%*	*$ (798,661)*	*-8.9%*
29										
30	*Total Lighting & Power 243 Revenues (rate schedule + riders)*			*$ 14,691,048*	*100.0%*		*$ 17,760,770*	*100.0%*	*$ 3,069,721*	*20.9%*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**									
2	*Lighting & Power 292 - Net Metering*									
3	*May - September*									
4	*Customer Charge*	*20*	*$ -*	*$ -*	*0.0%*	*$0.00*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
5	*all kWh*	*2,053,765*	*$ 0.0160*	*$ 32,860*	*27.6%*	*$ 0.0270*	*$ 55,452*	*27.7%*	*$ 22,591*	*68.8%*
6	*Billing kW*	*4,849*	*$ 7.55*	*$ 36,612*	*30.8%*	*$12.73*	*$ 61,731*	*30.9%*	*$ 25,119*	*68.6%*
7	*October - April*									
8	*Customer Charge*	*28*	*$ -*	*$ -*	*0.0%*	*$0.00*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
9	*all kWh*	*2,231,992*	*$ 0.0047*	*$ 10,490*	*8.8%*	*$ 0.0079*	*$ 17,633*	*8.8%*	*$ 7,142*	*68.1%*
10	*Billing kW*	*6,383*	*$ 6.10*	*$ 38,935*	*32.7%*	*$10.22*	*$ 65,233*	*32.6%*	*$ 26,297*	*67.5%*
11										
12										
13	*Total Customer Applications*	*48*								
14	*Total kWh*	*4,285,757*								
15	*Total kW*	*11,232*								
16	*Subtotal Lighting & Power 292 Revenues*			*$ 118,897*	*100.0%*		*$ 200,048*	*100.0%*	*$ 81,150*	*68.3%*
17	*Book-to-Bill Ratio*			*0.962*			*0.962*			
18	*Total Lighting & Power 292 Base Rate Revenues*			*$ 114,332*			*$ 192,366*			
19	*Lighting & Power 292 Revenues as a % of Total Class Revenues (A)*			*$ 114,332*	*37.5%*		*$ 192,366*	*52.8%*		
20										
21	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*		
22	*Energy Cost Recovery*	*4,285,757*	*$ 0.032419*	*$ 138,940*	*45.5%*	*$ 0.032419*	*$ 138,940*	*38.2%*	*$ -*	*0.0%*
23	*Energy Efficiency Cost Rate*	*4,285,757*	*$ 0.006610*	*$ 28,329*	*9.3%*	*$ 0.004280*	*$ 18,343*	*5.0%*	*$ (9,986)*	*-35.2%*
24	*Alternate Generation Recovery*	*114,332*	*7.79%*	*$ 8,906*	*2.9%*	*0.00%*	*$ -*	*0.0%*	*$ (8,906)*	*-100.0%*
25	*Environmental Compliance Surcharge*	*4,285,757*	*$ 0.003420*	*$ 14,657*	*4.8%*	*$ -*	*$ -*	*0.0%*	*$ (14,657)*	*-100.0%*
26	*Distribution Relability Request*	*4,285,757*	*$ -*	*$ -*	*0.0%*	*$ 0.003375*	*$ 14,464*	*4.0%*	*$ 14,464*	*#DIV/0!*
27	*Federal Tax Cut Adjustment*	*$114,332*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
28	*Subtotal Rate Schedule Riders*			*$ 190,833*	*62.5%*		*$ 171,747*	*47.2%*	*$ (19,085)*	*-10.0%*
29										
30	*Total Lighting & Power 292 Revenues (rate schedule + riders)*			*$ 305,165*	*100.0%*		*$ 364,114*	*100.0%*	*$ 58,949*	*19.3%*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**									
2	*Lighting & Power 060 -Master Metered*									
3	*May - September*									
4	*Customer Charge*	*10*	$ -	$ -	0.0%	$0.00	$ -	0.0%	$ -	#DIV/0!
5	*all kWh*	*435,607*	$ 0.0160	$ 6,970	25.3%	$ 0.0270	$ 11,761	25.4%	$ 4,792	68.7%
6	*Billing kW*	*1,203*	$ 7.55	$ 9,081	33.0%	$12.73	$ 15,312	33.1%	$ 6,230	68.6%
7	*October - April*									
8	*Customer Charge*	*14*	$ -	$ -	0.0%	$0.00	$ -	0.0%	$ -	#DIV/0!
9	*all kWh*	*464,073*	$ 0.0047	$ 2,181	7.9%	$ 0.0079	$ 3,666	7.9%	$ 1,485	68.1%
10	*Billing kW*	*1,525*	$ 6.10	$ 9,305	33.8%	$10.22	$ 15,589	33.6%	$ 6,285	67.5%
11										
12										
13	*Total Customer Applications*	*24*								
14	*Total kWh*	*899,680*								
15	*Total kW*	*2,728*								
16	*Subtotal Lighting & Power 060 Revenues*			$ 27,537	100.0%		$ 46,328	100.0%	$ 18,792	68.2%
17	*Book-to-Bill Ratio*			0.957			0.957			
18	*Total Lighting & Power 060 Base Rate Revenues*			$ 26,366			$ 44,359			
19	*Lighting & Power 060 Revenues as a % of Total Class Revenues (A)*			$ 26,366	39.6%		$ 44,359	55.2%		
20										
21	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*		
22	*Energy Cost Recovery*	*899,680*	$ 0.032419	$ 29,167	43.8%	$ 0.032419	$ 29,167	36.3%	$ -	0.0%
23	*Energy Efficiency Cost Rate*	*899,680*	$ 0.006610	$ 5,947	8.9%	$ 0.004280	$ 3,851	4.8%	$ (2,096)	-35.2%
24	*Alternate Generation Recovery*	*26,366*	7.79%	$ 2,054	3.1%	0.00%	$ -	0.0%	$ (2,054)	-100.0%
25	*Environmental Compliance Surcharge*	*899,680*	$ 0.003420	$ 3,077	4.6%	$ -	$ -	0.0%	$ (3,077)	-100.0%
26	*Distribution Relability Request*	*899,680*	$ -	$ -	0.0%	$ 0.003375	$ 3,036	3.8%	$ 3,036	#DIV/0!
27	*Federal Tax Cut Adjustment*	*$26,366*	0.00%	$ -	0.0%	0.00%	$ -	0.0%	$ -	#DIV/0!
28	*Subtotal Rate Schedule Riders*			$ 40,244	60.4%		$ 36,054	44.8%	$ (4,191)	-10.4%
29										
30	*Total Lighting & Power 060 Revenues (rate schedule + riders)*			$ 66,610	100.0%		$ 80,413	100.0%	$ 13,802	20.7%

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**									
2	*Lighting & Power 246 250 251 - Primary*									
3	*May - September*									
4	*Customer Charge*	*185*	$ -	$ -	*0.0%*	*$0.00*	$ -	*0.0%*	$ -	*#DIV/0!*
5	*all kWh*	*187,495,959*	$ 0.01565	$ 2,934,312	*31.3%*	$ 0.0257	$ 4,824,271	*31.3%*	$ 1,889,959	*64.4%*
6	*Billing kW*	*393,382*	$ 6.80	$ 2,674,996	*28.5%*	*$11.16*	$ 4,390,140	*28.5%*	$ 1,715,144	*64.1%*
7	*October - April*									
8	*Customer Charge*	*259*	$ -	$ -	*0.0%*	*$0.00*	$ -	*0.0%*	$ -	*#DIV/0!*
9	*all kWh*	*230,757,329*	$ 0.0045	$ 1,038,408	*11.1%*	$ 0.0074	$ 1,707,604	*11.1%*	$ 669,196	*64.4%*
10	*Billing kW*	*508,899*	$ 5.35	$ 2,722,612	*29.1%*	*$8.80*	$ 4,478,315	*29.1%*	$ 1,755,703	*64.5%*
11										
12										
13	*Total Customer Applications*	*444*								
14	*Total kWh*	*418,253,289*								
15	*Total kW*	*902,281*								
16	*Subtotal Lighting & Power Primary Revenues*			$ 9,370,328	*100.0%*		$ 15,400,331	*100.0%*	$ 6,030,003	*64.4%*
17	*Book-to-Bill Ratio*			*0.985*			*0.985*			
18	*Total Lighting & Power 246 250 251 Base Rate Revenues*			$ 9,233,211			$ 15,174,977			
19	*Lighting & Power 246 250 251 Revenues as a % of Total Class Revenues (A)*			$ 9,233,211	*35.7%*		$ 15,174,977	*50.8%*		
20										
21	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*		
22	*Energy Cost Recovery*	*418,253,289*	$ 0.031397	$ 13,131,899	*50.8%*	$ 0.031397	$ 13,131,899	*43.9%*	$ -	*0.0%*
23	*Energy Efficiency Cost Rate*	*205,634,774*	$ 0.006610	$ 1,359,246	*5.3%*	$ 0.004280	$ 880,117	*2.9%*	$ (479,129)	*-35.2%*
24	*Alternate Generation Recovery*	*9,233,211*	*7.79%*	$ 719,267	*2.8%*	*0.00%*	$ -	*0.0%*	$ (719,267)	*-100.0%*
25	*Environmental Compliance Surcharge*	*418,253,289*	$ 0.003420	$ 1,430,426	*5.5%*	$ -	$ -	*0.0%*	$ (1,430,426)	*-100.0%*
26	*Distribution Relability Request*	*418,253,289*	$ -	$ -	*0.0%*	$ 0.001682	$ 703,502	*2.4%*	$ 703,502	*#DIV/0!*
27	*Federal Tax Cut Adjustment*	*$9,233,211*	*0.00%*	$ -	*0.0%*	*0.00%*	$ -	*0.0%*	$ -	*#DIV/0!*
28	*Subtotal Rate Schedule Riders*			$ 16,640,838	*64.3%*		$ 14,715,517	*49.2%*	$ (1,925,320)	*-11.6%*
29										
30	*Total Lighting & Power 246 250 251 Revenues (rate schedule + riders)*			$ 25,874,049	*100.0%*		$ 29,890,494	*100.0%*	$ 4,016,445	*15.5%*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES												CHANGE	
(1)	(2)	(3)	(4)		(5)		(6)	(7)		(8)		(9)	(10)		(11)	
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $		REVENUE $		% OF REVENUES**	RATE $		REVENUE $		% OF REVENUES**	TOTAL REVENUE		%	
1	**RATE SCHEDULE DESCRIPTION**															
2	*Lighting & Power 249 - Primary W/C2*															
3	*May - September*															
4	*Customer Charge*	*50*	$	-	$	-	*0.0%*		$0.00	$	-	*0.0%*	$	-	#DIV/0!	
5	*all kWh*	*55,240,114*	$	0.01565	$	864,508	*31.0%*	$	0.0257	$	1,421,328	*31.0%*	$	556,820	64.4%	
6	*Billing kW*	*119,588*	$	6.80	$	813,196	*29.2%*		$11.16	$	1,334,598	*29.1%*	$	521,402	64.1%	
7	*October - April*															
8	*Customer Charge*	*70*	$	-	$	-	*0.0%*		$0.00	$	-	*0.0%*	$	-	#DIV/0!	
9	*all kWh*	*70,853,443*	$	0.0045	$	318,840	*11.4%*	$	0.0074	$	524,315	*11.5%*	$	205,475	64.4%	
10	*Billing kW*	*147,523*	$	5.35	$	789,247	*28.3%*		$8.80	$	1,298,200	*28.4%*	$	508,954	64.5%	
11																
12																
13	*Total Customer Applications*	*120*														
14	*Total kWh*	*126,093,556*														
15	*Total kW*	*267,110*														
16	*Subtotal Lighting & Power 249 Revenues*				$	2,785,791	*100.0%*			$	4,578,442	*100.0%*	$	1,792,651	64.3%	
17	*Book-to-Bill Ratio*					1.000					1.000					
18	*Total Lighting & Power 249 Base Rate Revenues*				$	2,786,235				$	4,579,171					
19	*Lighting & Power 249 Revenues as a % of Total Class Revenues (A)*				$	2,786,235	*37.0%*			$	4,579,171	*51.8%*				
20																
21	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*		*Present Factor $*		*% of Rider Revenues*	*Proposed Factor*		*Proposed Factor $*		*% of Rider Revenues*				
22	*Energy Cost Recovery*	*126,093,556*	$	0.031397	$	3,958,959	*52.5%*	$	0.031397	$	3,958,959	*44.8%*	$	-	0.0%	
23	*Energy Efficiency Cost Rate (opt out adj)*	*21,594,856*	$	0.006610	$	142,742	*1.9%*	$	0.004280	$	92,426	*1.0%*	$	(50,316)	-35.2%	
24	*Alternate Generation Recovery*	*2,786,235*		7.79%	$	217,048	*2.9%*		0.00%	$	-	*0.0%*	$	(217,048)	-100.0%	
25	*Environmental Compliance Surcharge*	*126,093,556*	$	0.003420	$	431,240	*5.7%*	$	-	$	-	*0.0%*	$	(431,240)	-100.0%	
26	*Distribution Relability Request*	*126,093,556*	$	-	$	-	*0.0%*	$	0.001682	$	212,089	*2.4%*	$	212,089	#DIV/0!	
27	*Federal Tax Cut Adjustment*	*$2,786,235*		0.00%	$	-	*0.0%*		0.00%	$	-	*0.0%*	$	-	#DIV/0!	
28	*Subtotal Rate Schedule Riders*				$	4,749,989	*63.0%*			$	4,263,475	*48.2%*	$	(486,514)	-10.2%	
29																
30	*Total Lighting & Power 249 Revenues (rate schedule + riders)*				$	7,536,224	*100.0%*			$	8,842,646	*100.0%*	$	1,306,422	17.3%	

Note: "PROPOSED RATES" spans columns (7)–(9).

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**									
2	*Lighting & Power 66 - Primary Master Metered*									
3	*May - September*									
4	*Customer Charge*	10	$ -	$ -	0.0%	$0.00	$ -	0.0%	$ -	#DIV/0!
5	*all kWh*	978,754	$ 0.01565	$ 15,318	20.1%	$ 0.0257	$ 25,183	20.1%	$ 9,866	64.4%
6	*Billing kW*	5,018	$ 6.80	$ 34,124	44.8%	$11.16	$ 56,004	44.7%	$ 21,880	64.1%
7	*October - April*									
8	*Customer Charge*	14	$ -	$ -	0.0%	$0.00	$ -	0.0%	$ -	#DIV/0!
9	*all kWh*	1,183,164	$ 0.0045	$ 5,324	7.0%	$ 0.0074	$ 8,755	7.0%	$ 3,431	64.4%
10	*Billing kW*	4,004	$ 5.35	$ 21,424	28.1%	$8.80	$ 35,239	28.2%	$ 13,815	64.5%
11										
12										
13	*Total Customer Applications*	24								
14	*Total kWh*	2,161,919								
15	*Total kW*	9,023								
16	*Subtotal Lighting & Power 66 Revenues*			$ 76,190	100.0%		$ 125,182	100.0%	$ 48,992	64.3%
17	*Book-to-Bill Ratio*			1.083			1.083			
18	*Total Lighting & Power 66 Base Rate Revenues*			$ 82,521			$ 135,584			
19	*Lighting & Power 66 Revenues as a % of Total Class Revenues (A)*			$ 82,521	46.2%		$ 135,584	62.7%		
20										
21	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*		
22	*Energy Cost Recovery*	2,161,919	$ 0.031397	$ 67,878	38.0%	$ 0.031397	$ 67,878	31.4%	$ -	0.0%
23	*Energy Efficiency Cost Rate*	2,161,919	$ 0.006610	$ 14,290	8.0%	$ 0.004280	$ 9,253	4.3%	$ (5,037)	-35.2%
24	*Alternate Generation Recovery*	82,521	7.79%	$ 6,428	3.6%	0.00%	$ -	0.0%	$ (6,428)	-100.0%
25	*Environmental Compliance Surcharge*	2,161,919	$ 0.003420	$ 7,394	4.1%	$ -	$ -	0.0%	$ (7,394)	-100.0%
26	*Distribution Relability Request*	2,161,919	$ -	$ -	0.0%	$ 0.001682	$ 3,636	1.7%	$ 3,636	#DIV/0!
27	*Federal Tax Cut Adjustment*	$82,521	0.00%	$ -	0.0%	0.00%	$ -	0.0%	$ -	#DIV/0!
28	*Subtotal Rate Schedule Riders*			$ 95,990	53.8%		$ 80,767	37.3%	$ (15,223)	-15.9%
29										
30	*Total Lighting & Power 66 Revenues (rate schedule + riders)*			$ 178,511	100.0%		$ 216,351	100.0%	$ 37,840	21.2%

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**									
2	*Lighting & Power 336*									
3	*May - September*									
4	*Customer Charge*	*25*	*$ -*	*$ -*	*0.0%*	*$0.00*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
5	*all kWh*	*11,992,581*	*$ 0.01565*	*$ 187,684*	*19.2%*	*$ 0.0257*	*$ 308,569*	*16.6%*	*$ 120,885*	*64.4%*
6	*Billing kW*	*71,634*	*$ 6.80*	*$ 487,113*	*49.8%*	*$11.16*	*$ 799,439*	*43.1%*	*$ 312,326*	*64.1%*
7	*October - April*									
8	*Customer Charge*	*35*	*$ -*	*$ -*	*0.0%*	*$0.00*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
9	*all kWh*	*16,804,465*	*$ 0.0045*	*$ 75,620*	*7.7%*	*$ 0.0074*	*$ 124,353*	*6.7%*	*$ 48,733*	*64.4%*
10	*Billing kW*	*99,457*	*$ 5.35*	*$ 532,095*	*54.4%*	*$8.80*	*$ 875,222*	*47.2%*	*$ 343,127*	*64.5%*
11										
12	*Minimum Charge**	*13,406*	*$ 5.96*	*$ 79,864*	*8.2%*	*$ 9.79*	*$ 131,224*	*7.1%*		
13	*Curtailable kW Credit*	*125,434*	*$ 3.06*	*$ (383,827)*	*-39.2%*	*$ 3.06*	*$ (383,827)*	*-20.7%*	*$ -*	*0.0%*
14										
15	*Total Customer Applications*	*60*								
16	*Total kWh*	*28,797,046*								
17	*Total kW*	*171,091*								
18	*Subtotal Lighting & Power 336 Revenues*			*$ 978,549*	*100.0%*		*$ 1,854,980*	*100.0%*	*$ 825,070*	*84.3%*
19	*Book-to-Bill Ratio*			*0.988*			*0.988*			
20	*Total Lighting & Power 336 Base Rate Revenues*			*$ 966,899*			*$ 1,832,894*			
21	*Lighting & Power 336 Revenues as a % of Total Class Revenues (A)*			*$ 966,899*	*44.3%*		*$ 1,832,894*	*63.8%*		
22										
23	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*		
24	*Energy Cost Recovery*	*28,797,046*	*$ 0.031397*	*$ 904,141*	*41.4%*	*$ 0.031397*	*$ 904,141*	*31.5%*	*$ -*	*0.0%*
25	*Energy Efficiency Cost Rate (opt out adj)*	*20,670,628*	*$ 0.006610*	*$ 136,633*	*6.3%*	*$ 0.004280*	*$ 88,470*	*3.1%*	*$ (48,163)*	*-35.2%*
26	*Alternate Generation Recovery*	*966,899*	*7.79%*	*$ 75,321*	*3.5%*	*0.00%*	*$ -*	*0.0%*	*$ (75,321)*	*-100.0%*
27	*Environmental Compliance Surcharge*	*28,797,046*	*$ 0.003420*	*$ 98,486*	*4.5%*	*$ -*	*$ -*	*0.0%*	*$ (98,486)*	*-100.0%*
28	*Distribution Relability Request*	*28,797,046*	*$ -*	*$ -*	*0.0%*	*$ 0.001682*	*$ 48,437*	*1.7%*	*$ 48,437*	*#DIV/0!*
29	*Federal Tax Cut Adjustment*	*$966,899*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
30	*Subtotal Rate Schedule Riders*			*$ 1,214,581*	*55.7%*		*$ 1,041,048*	*36.2%*	*$ (173,533)*	*-14.3%*
31										
32	*Total Lighting & Power 336 Revenues (rate schedule + riders)*			*$ 2,181,480*	*100.0%*		*$ 2,873,942*	*100.0%*	*$ 692,462*	*31.7%*

**estimated minimum kW revenue adjustment*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**									
2	*Lighting & Power TOU Secondary 223*									
3	*On-Peak July, August, September 1-7 pm*									
4	*Customer Charge*	*10*	*$ -*	*$ -*	*0.0%*	*$0.00*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
5	*all kWh*	*330,743*	*$ 0.0556*	*$ 18,389*	*8.0%*	*$ 0.1039*	*$ 34,364*	*6.7%*	*$ 15,975*	*86.9%*
6	*Billing kW*	*7,703*	*$ 11.65*	*$ 89,734*	*38.9%*	*$21.33*	*$ 164,294*	*31.9%*	*$ 74,560*	*83.1%*
7	*Off-Peak*									
8	*Customer Charge*	*14*	*$ -*	*$ -*	*0.0%*	*$0.00*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
9	*all kWh*	*5,936,834*	*$ 0.0070*	*$ 41,558*	*18.0%*	*$ 0.0161*	*$ 95,583*	*18.6%*	*$ 54,025*	*130.0%*
10	*Billing kW*	*24,975*	*$ 3.25*	*$ 81,169*	*35.2%*	*$8.82*	*$ 220,279*	*42.8%*	*$ 139,111*	*171.4%*
11										
12										
13	*Total Customer Applications*	*24*								
14	*Total kWh*	*6,267,577*								
15	*Total kW*	*32,677*								
16	*Subtotal Lighting & Power 223 Revenues*			*$ 230,850*	*100.0%*		*$ 514,521*	*100.0%*	*$ 283,671*	*122.9%*
17	*Book-to-Bill Ratio*			*1.076*			*1.076*			
18	*Total Lighting & Power 223 Base Rate Revenues*			*$ 248,498*			*$ 553,854*			
19	*Lighting & Power 223 Revenues as a % of Total Class Revenues (A)*			*$ 248,498*	*46.5%*		*$ 553,854*	*68.8%*		
20										
21	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*		
22	*Energy Cost Recovery*	*6,267,577*	*$ 0.032419*	*$ 203,189*	*38.1%*	*$ 0.032419*	*$ 203,189*	*25.2%*	*$ -*	*0.0%*
23	*Energy Efficiency Cost Rate*	*6,267,577*	*$ 0.006610*	*$ 41,429*	*7.8%*	*$ 0.004280*	*$ 26,825*	*3.3%*	*$ (14,603)*	*-35.2%*
24	*Alternate Generation Recovery*	*248,498*	*7.79%*	*$ 19,358*	*3.6%*	*0.00%*	*$ -*	*0.0%*	*$ (19,358)*	*-100.0%*
25	*Environmental Compliance Surcharge*	*6,267,577*	*$ 0.003420*	*$ 21,435*	*4.0%*	*$ -*	*$ -*	*0.0%*	*$ (21,435)*	*-100.0%*
26	*Distribution Relability Request*	*6,267,577*	*$ -*	*$ -*	*0.0%*	*$ 0.003375*	*$ 21,153*	*2.6%*	*$ 21,153*	*#DIV/0!*
27	*Federal Tax Cut Adjustment*	*$248,498*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
28	*Subtotal Rate Schedule Riders*			*$ 285,410*	*53.5%*		*$ 251,167*	*31.2%*	*$ (34,243)*	*-12.0%*
29										
30	*Total Lighting & Power 223 Revenues (rate schedule + riders)*			*$ 533,908*	*100.0%*		*$ 805,021*	*100.0%*	*$ 271,113*	*50.8%*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**	[redacted]								
2	*Lighting & Power TOU Primary 225*									
3	*On-Peak July, August, September 1-7 pm*									
4	*Customer Charge*									
5	*all kWh*									
6	*Billing kW*									
7	*Off-Peak all other*									
8	*Customer Charge*									
9	*all kWh*									
10	*Billing kW*									
11										
12										
13	*Total Customer Applications*									
14	*Total kWh*									
15	*Total kW*									
16	*Subtotal Lighting & Power 225 Revenues*									
17	*Book-to-Bill Ratio*									
18	*Total Lighting & Power 225 Base Rate Rev*									
19	*Lighting & Power 225 Revenues as a % of*									
20										
21	*Riders & Requests - Adjusted Test Year*									
22	*Energy Cost Recovery*									
23	*Energy Efficiency Cost Rate*									
24	*Alternate Generation Recovery*									
25	*Environmental Compliance Surcharge*									
26	*Distribution Relability Request*									
27	*Federal Tax Cut Adjustment*									
28	*Subtotal Rate Schedule Riders*									
29										
30	*Total Lighting & Power 225 Revenues (rate*									

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**	[redacted]								
2	*Large Lighting & Power 346 Primary*									
3	*May - September*									
4	*Customer Charge*									
5	*all kWh*									
6	*Billing kW*									
7	*October - April*									
8	*Customer Charge*									
9	*all kWh*									
10	*Billing kW*									
11										
12										
13	*Total Customer Applications*									
14	*Total kWh*									
15	*Total kW*									
16	*Subtotal Large Lighting & Power 346 Rev*									
17	*Book-to-Bill Ratio*									
18	*Total Large Lighting & Power 346 Base R*									
19	*Large Lighting & Power 346 Revenues as*									
20										
21	*Riders & Requests - Adjusted Test Year*									
22	*Energy Cost Recovery*									
23	*Energy Efficiency Cost Rate*									
24	*Alternate Generation Recovery*									
25	*Environmental Compliance Surcharge*									
26	*Distribution Reliability Request*									
27	*Federal Tax Cut Adjustment*									
28	*Subtotal Rate Schedule Riders*									
29										
30	*Total Large Lighting & Power 346 Revenu*									

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**	[redacted]								
2	*Large Lighting & Power 336 Primary Firm*									
3	*May - September*									
4	*Customer Charge*									
5	*all kWh*									
6	*Billing kW*									
7	*October - April*									
8	*Customer Charge*									
9	*all kWh*									
10	*Billing kW*									
11										
12										
13	*Total Customer Applications*									
14	*Total kWh*									
15	*Total kW*									
16	*Subtotal Large Lighting & Power 336 Reven*									
17	*Book-to-Bill Ratio*									
18	*Total Large Lighting & Power 336 Base Rat*									
19	*Large Lighting & Power 336 Revenues as a*									
20										
21	*Riders & Requests - Adjusted Test Year*									
22	*Energy Cost Recovery*									
23	*Energy Efficiency Cost Rate*									
24	*Alternate Generation Recovery*									
25	*Environmental Compliance Surcharge*									
26	*Distribution Relability Request*									
27	*Federal Tax Cut Adjustment*									
28	*Subtotal Rate Schedule Riders*									
29										
30	*Total Large Lighting & Power 336 Revenues*									

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component using pro forma year billing determinants, at present and proposed rates for every rating period (e.g., on-peak, summer off-peak, etc.). Please provide the percent of total rate schedule revenue that each rate schedule component represents.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR	RATE	REVENUE	% OF	RATE	REVENUE	% OF	TOTAL	
1	**RATE SCHEDULE DESCRIPTION**	[redacted]								
2	*Large Lighting & Power 342 Transmission*									
3	*May - September*									
4	*Customer Charge*									
5	*all kWh*									
6	*Billing kW*									
7	*October - April*									
8	*Customer Charge*									
9	*all kWh*									
10	*Billing kW*									
11										
12	*IP kW Credit*									
13										
14	*Total Customer Applications*									
15	*Total kWh*									
16	*Total kW*									
17	*Subtotal Large Lighting & Power 342 Reve*									
18	*Book-to-Bill Ratio*									
19	*Total Large Lighting & Power 342 Base Ra*									
20	*Large Lighting & Power 342 Revenues as a*									
21										
22	*Riders & Requests - Adjusted Test Year*									
23	*Energy Cost Recovery*									
24	*Energy Efficiency Cost Rate*									
25	*Alternate Generation Recovery*									
26	*Environmental Compliance Surcharge*									
27	*Federal Tax Cut Adjustment*									
28	*Subtotal Rate Schedule Riders*									
29										
30	*Total Large Lighting & Power 342 Revenue*									

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component using pro forma year billing determinants, at present and proposed rates for every rating period (e.g., on-peak, summer off-peak, etc.). Please provide the percent of total rate schedule revenue that each rate schedule component represents.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	RATE	CUSTOMER BILLS,								
LINE	COMPONENT	CONSUMPTION, OR	RATE	REVENUE	% OF	RATE	REVENUE	% OF	TOTAL	
NO.	DESCRIPTION	[redacted]								
1	**RATE SCHEDULE DESCRIPTION**									
2	*Pulp & Paper Mill 326*									
3										
4	*Customer Charge*									
5	*all kWh*									
6	*Billing kW*									
7										
8	*Backup Service*									
9										
10										
11	*Total Customer Applications*									
12	*Total kWh*									
13	*Total kW*									
14	*Subtotal Pulp & Paper Mill 326 Revenues*									
15	*Book-to-Bill Ratio*									
16	*Total Pulp & Paper Mill 326 Base Rate Rev*									
17	*Pulp & Paper Mill 326 Revenues as a % of*									
18										
19	*Riders & Requests - Adjusted Test Year*									
20	*Energy Cost Recovery*									
21	*Energy Efficiency Cost Rate*									
22	*Alternate Generation Recovery*									
23	*Environmental Compliance Surcharge*									
24	*Federal Tax Cut Adjustment*									
25	*Subtotal Rate Schedule Riders*									
26										
27	*Total Pulp & Paper Mill 326 Revenues (rate*									

Supporting Schedules
(a) E-11.2 & supporting workpapers

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**									
2	*Municipal Service 544*									
3	*May - September*									
4	*Customer Charge*	*2,413*	*$ 5.35*	*$ 12,910*	*5.1%*	*$7.36*	*$ 17,760*	*5.1%*	*$ 4,850*	*37.6%*
5	*all kWh*	*2,471,303*	*$ 0.0405*	*$ 100,088*	*39.7%*	*$ 0.0557*	*$ 137,652*	*39.7%*	*$ 37,564*	*37.5%*
1										
2	*October - April*									
3	*Customer Charge*	*3,378*	*$ 5.35*	*$ 18,074*	*7.2%*	*$7.36*	*$ 24,864*	*7.2%*	*$ 6,790*	*37.6%*
4	*all kWh*	*3,241,795*	*$ 0.0359*	*$ 116,380*	*46.2%*	*$ 0.0494*	*$ 160,145*	*46.2%*	*$ 43,764*	*37.6%*
5	*Minimum Bill*	*3,439*	*$ 1.28*	*$ 4,402*	*1.7%*	*$1.76*	*$ 6,053*	*1.7%*		
6	*Total Customer Applications*	*5,791*								
7	*Total kWh*	*5,713,097*								
8										
9	*Subtotal Municipal Service 544 Revenues*			*$ 251,854*	*100.0%*		*$ 346,473*	*100.0%*	*$ 92,969*	*36.9%*
10	*Book-to-Bill Ratio*			*0.971*			*0.971*			
11	*Total Municipal Service 544 Base Rate Revenues*			*$ 244,646*			*$ 336,558*			
12	*Municipal Service 544 Revenues as a % of Total Class Revenues (A)*			*$ 244,646*	*48.5%*		*$ 336,558*	*59.5%*		
13										
14	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*		
15	*Energy Cost Recovery*	*5,713,097*	*$ 0.032419*	*$ 185,213*	*36.7%*	*$ 0.032419*	*$ 185,213*	*32.7%*	*$ -*	*0.0%*
16	*Energy Efficiency Cost Rate*	*5,713,097*	*$ 0.007620*	*$ 43,534*	*8.6%*	*$ 0.004290*	*$ 24,509*	*4.3%*	*$ (19,025)*	*-43.7%*
17	*Alternate Generation Recovery*	*$244,646*	*4.30%*	*$ 10,520*	*2.1%*	*0.00%*	*$ -*	*0.0%*	*$ (10,520)*	*-100.0%*
18	*Environmental Compliance Surcharge*	*5,713,097*	*$ 0.003540*	*$ 20,224*	*4.0%*	*$ -*	*$ -*	*0.0%*	*$ (20,224)*	*-100.0%*
19	*Distribution Relability Request*	*5,713,097*	*$ -*	*$ -*	*0.0%*	*$ 0.003379*	*$ 19,305*	*3.4%*	*$ 19,305*	*#DIV/0!*
20	*Federal Tax Cut Adjustment*	*$244,646*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
21	*Subtotal Rate Schedule Riders*			*$ 259,491*	*51.5%*		*$ 229,027*	*40.5%*	*$ (30,464)*	*-11.7%*
22										
23	*Total Municipal Service 544 Revenues (rate schedule + riders)*			*$ 504,137*	*100.0%*		*$ 565,584*	*100.0%*	*$ 61,447*	*12.2%*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**									
2	*Municipal Pumping 550*									
3	*May - September*									
4	*Customer Charge*	*1,041*	*$ 5.35*	*$ 5,567*	*1.3%*	*$7.36*	*$ 7,659*	*1.3%*	*$ 2,092*	*37.6%*
5	*all kWh*	*5,259,856*	*$ 0.0358*	*$ 188,303*	*45.0%*	*$ 0.0492*	*$ 258,785*	*45.0%*	*$ 70,482*	*37.4%*
1										
2	*October - April*									
3	*Customer Charge*	*1,457*	*$ 5.35*	*$ 7,794*	*1.9%*	*$7.36*	*$ 10,723*	*1.9%*	*$ 2,928*	*37.6%*
4	*all kWh*	*6,845,368*	*$ 0.0310*	*$ 212,206*	*50.7%*	*$ 0.0426*	*$ 291,613*	*50.7%*	*$ 79,406*	*37.4%*
5	*Minimum Bill*	*3,404*	*$ 1.28*	*$ 4,357*	*1.0%*	*$1.76*	*$ 5,991*	*1.0%*		
6	*Total Customer Applications*	*2,498*								
7	*Total kWh*	*12,105,225*								
8										
9	*Subtotal Municipal Pumping 550 Revenues*			*$ 418,228*	*100.0%*		*$ 574,770*	*100.0%*	*$ 154,908*	*37.0%*
10	*Book-to-Bill Ratio*			*0.971*			*0.971*			
11	*Total Municipal Pumping 550 Base Rate Revenues*			*$ 406,109*			*$ 558,115*			
12	*Municipal Pumping 550 Revenues as a % of Total Class Revenues (A)*			*$ 406,109*	*42.2%*		*$ 558,115*	*53.5%*		
13										
14	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*		
15	*Energy Cost Recovery*	*12,105,225*	*$ 0.032419*	*$ 392,439*	*40.8%*	*$ 0.032419*	*$ 392,439*	*37.6%*	*$ -*	*0.0%*
16	*Energy Efficiency Cost Rate*	*12,105,225*	*$ 0.007620*	*$ 92,242*	*9.6%*	*$ 0.004290*	*$ 51,931*	*5.0%*	*$ (40,310)*	*-43.7%*
17	*Alternate Generation Recovery*	*406,109*	*4.30%*	*$ 17,463*	*1.8%*	*$ -*	*$ -*	*0.0%*	*$ (17,463)*	*-100.0%*
18	*Environmental Compliance Surcharge*	*12,105,225*	*$ 0.004490*	*$ 54,352*	*5.6%*	*$ -*	*$ -*	*0.0%*	*$ (54,352)*	*-100.0%*
19	*Distribution Relability Request*	*12,105,225*	*$ -*	*$ -*	*0.0%*	*$ 0.003379*	*$ 40,904*	*3.9%*	*$ 40,904*	*#DIV/0!*
20	*Federal Tax Cut Adjustment*	*$406,109*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
21	*Subtotal Rate Schedule Riders*			*$ 556,496*	*57.8%*		*$ 485,274*	*46.5%*	*$ (71,222)*	*-12.8%*
22										
23	*Total Municipal Pumping 550 Revenues (rate schedule + riders)*			*$ 962,605*	*100.0%*		*$ 1,043,389*	*100.0%*	*$ 80,784*	*8.4%*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

			PRESENT RATES			PROPOSED RATES			CHANGE	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
LINE NO.	RATE COMPONENT DESCRIPTION	CUSTOMER BILLS, CONSUMPTION, OR DEMAND* (a)	RATE $	REVENUE $	% OF REVENUES**	RATE $	REVENUE $	% OF REVENUES**	TOTAL REVENUE	%
1	**RATE SCHEDULE DESCRIPTION**									
2	*Municipal Service 540/549*									
3	*May - September*									
4	*Customer Charge*	*317*	*$ 5.35*	*$ 1,694*	*1.4%*	*$7.36*	*$ 2,331*	*1.4%*	*$ 637*	*37.6%*
5	*all kWh*	*1,358,845*	*$ 0.0358*	*$ 48,647*	*40.5%*	*$ 0.0492*	*$ 66,855*	*40.5%*	*$ 18,209*	*37.4%*
1										
2	*October - April*									
3	*Customer Charge*	*443*	*$ 5.35*	*$ 2,372*	*2.0%*	*$7.36*	*$ 3,263*	*2.0%*	*$ 891*	*37.6%*
4	*all kWh*	*2,176,319*	*$ 0.0310*	*$ 67,466*	*56.1%*	*$ 0.0426*	*$ 92,711*	*56.1%*	*$ 25,245*	*37.4%*
5	*Minimum Bill*	*0*	*$ 1.28*		*0.0%*	*$1.76*	*$ -*	*0.0%*		
6	*Total Customer Applications*	*760*								
7	*Total kWh*	*3,535,164*								
8										
9	*Subtotal Municipal Pumping 540/549 Revenues*			*$ 120,179*	*100.0%*		*$ 165,161*	*100.0%*	*$ 44,982*	*37.4%*
10	*Book-to-Bill Ratio*			*0.856*			*0.856*			
11	*Total Municipal Pumping 540/549 Base Rate Revenues*			*$ 102,901*			*$ 141,416*			
12	*Municipal Pumping 540/549 Revenues as a % of Total Class Revenues (A)*			*$ 102,901*	*38.9%*		*$ 141,416*	*49.9%*		
13										
14	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*		
15	*Energy Cost Recovery*	*3,535,164*	*$ 0.032419*	*$ 114,606*	*43.3%*	*$ 0.032419*	*$ 114,606*	*40.5%*	*$ -*	*0.0%*
16	*Energy Efficiency Cost Rate*	*3,535,164*	*$ 0.007620*	*$ 26,938*	*10.2%*	*$ 0.004290*	*$ 15,166*	*5.4%*	*$ (11,772)*	*-43.7%*
17	*Alternate Generation Recovery*	*102,901*	*4.30%*	*$ 4,425*	*1.7%*	*$ -*	*$ -*	*0.0%*	*$ (4,425)*	*-100.0%*
18	*Environmental Compliance Surcharge*	*3,535,164*	*$ 0.004490*	*$ 15,873*	*6.0%*	*$ -*	*$ -*	*0.0%*	*$ (15,873)*	*-100.0%*
19	*Distribution Relability Request*	*3,535,164*	*$ -*	*$ -*	*0.0%*	*$ 0.003379*	*$ 11,945*	*4.2%*	*$ 11,945*	*#DIV/0!*
20	*Federal Tax Cut Adjustment*	*$102,901*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
21	*Subtotal Rate Schedule Riders*			*$ 161,842*	*61.1%*		*$ 141,718*	*50.1%*	*$ (20,124)*	*-12.4%*
22										
23	*Total Municipal Pumping 540/549 Revenues (rate schedule + riders)*			*$ 264,743*	*100.0%*		*$ 283,134*	*100.0%*	*$ 18,390*	*6.9%*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

Revenue Distribution
-39.48%

LINE NO.	Description	Tariff Modifier	Modifier	Monthly kWh per Fixture	Annual kWh	Monthly Fixture Count	kWh	Annual Fixture Count	Present Tariff Price	Facilities Charge	Present Annual Base Revenue	Proposed Tariff Price	Facilities Charge	Proposed Annual Base Revenue
(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	Private Lighting (Closed)													
2	Mercury Vapor													
3	175 Watt (on existing pole)	302	091	68	816	2,296	1,873,536	27,552	$ 5.85	$ 725.36	$ 161,179.20	$ 3.54	$ 725.36	$ 97,534.08
4	175 Watt (w/pole)	303	092	68	816	810	660,960	9,720	$ 13.63	$ 1,052.83	$ 132,483.60	$ 8.25	$ 1,052.83	$ 80,190.00
5														
6	Area Lighitng (Closed)													
7	Mercury Vapor													
8	100 Watt	322	094	42	504	3	1,512	36	$ 10.14	$ 172.08	$ 365.04	$ 6.14	$ 172.08	$ 221.04
9	175 Watt	323	137	68	816	335	273,360	4,020	$ 10.23	$ 38,644.54	$ 41,124.60	$ 6.19	$ 38,644.54	$ 24,883.80
10	250 Watt	324	138	98	1,176	25	29,400	300	$ 10.61	$ 907.44	$ 3,183.00	$ 6.42	$ 907.44	$ 1,926.00
11	400 Watt	325	096	155	1,860	65	120,900	780	$ 10.65	$ 2,924.73	$ 8,307.00	$ 6.45	$ 2,924.73	$ 5,031.00
12	700 Watt	326	139	257	3,084	0	0	0	$ 10.65	$ -	$ -	$ 6.45	$ -	$ -
13	1,000 Watt	327	140	364	4,368	8	34,944	96	$ 15.71	$ 992.89	$ 1,508.16	$ 9.51	$ 992.89	$ 912.96
14														
15	Metal Halide													
16	400 Watt	336	132	156	1,872	812	1,520,064	9,744	$ 10.40	$ 80,780.55	$ 101,337.60	$ 6.29	$ 80,780.55	$ 61,289.76
17	1,000 Watt	337	135	373	4,476	666	2,981,016	7,992	$ 13.00	$ 107,135.19	$ 103,896.00	$ 7.87	$ 107,135.19	$ 62,897.04
18														
19	High Pressure Sodium													
20	70 Watt	350	115	35	420	1	420	12	$ 8.06	$ 42.48	$ 96.72	$ 4.88	$ 42.48	$ 58.56
21	100 Watt	351	098	49	588	2,466	1,450,008	29,592	$ 8.10	$ 139,370.78	$ 239,695.20	$ 4.90	$ 139,370.78	$ 145,000.80
22	250 Watt	352	104	105	1,260	78	98,280	936	$ 9.35	$ 6,067.98	$ 8,751.60	$ 5.66	$ 6,067.98	$ 5,297.76
23	400 Watt	346	108	165	1,980	1,023	2,025,540	12,276	$ 10.36	$ 125,834.59	$ 127,179.36	$ 6.27	$ 125,834.59	$ 76,970.52
24	1,000 Watt	347	112	388	4,656	647	3,012,432	7,764	$ 13.53	$ 113,135.93	$ 105,046.92	$ 8.19	$ 113,135.93	$ 63,587.16
25														
26	Outdoor Lighting (Open)													
27	Mercury Vapor													
28	175 Watt	400	093	68	816	245	199,920	2,940	$ 10.23	$ 13,687.83	$ 30,076.20	$ 6.19	$ 13,687.83	$ 18,198.60
29	400 Watt	401	095	155	1,860	9	16,740	108	$ 10.65	$ 414.17	$ 1,150.20	$ 6.45	$ 414.17	$ 696.60
30														
31	Metal Halide													
32	400 Watt	402	133	156	1,872	695	1,301,040	8,340	$ 10.40	$ 64,706.92	$ 86,736.00	$ 6.29	$ 64,706.92	$ 52,458.60
33	1,000 Watt	403	136	373	4,476	866	3,876,216	10,392	$ 13.00	$ 100,900.11	$ 135,096.00	$ 7.87	$ 100,900.11	$ 81,785.04
34														
35	High Pressure Sodium													
36	100 Watt	404	097	49	588	3,743	2,200,884	44,916	$ 8.10	$ 180,719.12	$ 363,819.60	$ 4.90	$ 180,719.12	$ 220,088.40
37	250 Watt	405	103	105	1,260	131	165,060	1,572	$ 9.35	$ 14,555.09	$ 14,698.20	$ 5.66	$ 14,555.09	$ 8,897.52
38	400 Watt	406	107	165	1,980	899	1,780,020	10,788	$ 10.36	$ 95,134.32	$ 111,763.68	$ 6.27	$ 95,134.32	$ 67,640.76
39	1,000 Watt	407	111	388	4,656	645	3,003,120	7,740	$ 13.53	$ 80,850.96	$ 104,722.20	$ 8.19	$ 80,850.96	$ 63,390.60
40														
41	Total			3,850	46,200	16,468		197,616		$ 1,168,755.89	$ 1,882,216.08		$ 1,168,755.89	$ 1,138,956.60
42														
43	Base Rate Revenue + Facilities Revenue										$ 3,050,972			$ 2,307,712
44	Book-to-Bill Ratio										1.04			1.04
45	*Total Private Outdoor Area Base Rate Revenues (A)*										$ 3,169,707			$ 2,397,522
46														
47	*Private Outdoor Area Revenues as a % of Total Class Revenues*										74.33%			68.98%

48	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*	*Total Revenue Change*	*Total Percent Change*
49	*Energy Cost Recovery*	*26,642,383*	*$ 0.032419*	*$ 863,719*	*20.3%*	*$ 0.032419*	*$ 863,719*	*24.8%*	*$ -*	*0.0%*
50	*Energy Efficiency Cost Rate*	*26,642,383*	*$ 0.005340*	*$ 142,270*	*3.3%*	*$ 0.003460*	*$ 92,183*	*2.7%*	*$ (50,088)*	*-35.2%*
51	*Alternate Generation Recovery*	*3,169,707*	*1.10%*	*$ 34,867*	*0.8%*	*$ -*	*$ -*	*0.0%*	*$ (34,867)*	*-100.0%*
52	*Environmental Compliance Surcharge*	*26,642,383*	*$ 0.002010*	*$ 53,551*	*1.3%*	*$ -*	*$ -*	*0.0%*	*$ (53,551)*	*-100.0%*
53	*Distribution Relability Request*	*26,642,383*	*$ -*	*$ -*	*0.0%*	*$ 0.004594*	*$ 122,395*	*3.5%*	*$ 122,395*	*#DIV/0!*
54	*Federal Tax Cut Adjustment*	*$3,169,707*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
55	*Subtotal Rate Schedule Riders*			*$ 1,094,408*	*25.7%*		*$ 1,078,297*	*31.0%*	*$ (16,111)*	*-1.5%*
56										
57	*Total Private Outdoor Area Revenues (rate schedule + riders)*			*$ 4,264,115*	*100.0%*		*$ 3,475,819*	*100.0%*	*$ (788,296)*	*-18.5%*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

Revenue Distribution -37.14%

LINE NO.	Description	Tariff Modifier	MACCS Modifier	Monthly kWh per Fixture	Annual kWh	Monthly Fixture Count	kWh	Annual Fixture Count	Present Tariff Price	Facilities Charge	Present Annual Base Revenue	Proposed Tariff Price	Facilities Charge	Proposed Annual Base Revenue
(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	MSL-529 (closed)													
2	Mercury Vapor													
3	75 Watt	031	MVOPN	30	360	1,191	428,760	14,292	$ 5.98		$ 85,466.16	$ 3.76		$ 53,737.92
4	100 Watt	032	MVOPN	42	504	905	456,120	10,860	$ 6.08		$ 66,028.80	$ 3.82		$ 41,485.20
5	175 Watt	033	MVOPN	68	816	2,246	1,832,736	26,952	$ 6.23		$ 167,910.96	$ 3.92		$ 105,651.84
6	400 Watt - on wood pole	028	MVENC	155	1,860	2	3,720	24	$ 6.78		$ 162.72	$ 4.26		$ 102.24
7	400 Watt - on wood pole	035	MVSER	155	1,860	6	11,160	72	$ 7.43		$ 534.96	$ 4.67		$ 336.24
8	400 Watt - on wood pole	036	MVENC	155	1,860	266	494,760	3,192	$ 7.43		$ 23,716.56	$ 4.67		$ 14,906.64
9	400 Watt - on steel pole	037	MVENC	155	1,860	147	273,420	1,764	$ 11.10		$ 19,580.40	$ 6.98		$ 12,312.72
10	400 Watt - on wood pole	039	MVENC	155	1,860	2	3,720	24	$ 11.73		$ 281.52	$ 7.37		$ 176.88
11	400 Watt - on steel pole	041	MVENC	155	1,860	26	48,360	312	$ 19.83		$ 6,186.96	$ 12.47		$ 3,890.64
12														
13	MSL-530 (closed)													
14	4,000 Lumen - 100 Watt	030	MVPST	42	504	39	19,656	468	$ 7.78		$ 3,641.04	$ 4.89		$ 2,288.52
15														
16	Total				13,344	4,830		57,960		$ -	$ 373,510.08			$ 234,888.84
17														
18	Base Rate Revenue + Facilities Revenue										$ 373,510.08			$ 234,888.84
19	Book-to-Bill Ratio					-					$ 0.91			$ 0.91
20	Total Municipal Base Rate Revenues (A)										$ 339,705.81			$ 213,630.39
21	Municipal Street Lighting as a % of Total Class Revenues										69.4%			59.0%
22														

23	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*	*Total Revenue Change*	*Total Percent Change*
24	*Energy Cost Recovery*	*3,672,400*	*$ 0.032419*	*$ 119,056*	*24.3%*	*$ 0.032419*	*$ 119,056*	*32.9%*	*$ -*	*0.0%*
25	*Energy Efficiency Cost Rate*	*3,672,400*	*$ 0.005340*	*$ 19,611*	*4.0%*	*$ 0.003460*	*$ 12,707*	*3.5%*	*$ (6,904)*	*-35.2%*
26	*Alternate Generation Recovery*	*339,706*	*1.10%*	*$ 3,737*	*0.8%*	*$ -*	*$ -*	*0.0%*	*$ (3,737)*	*-100.0%*
27	*Environmental Compliance Surcharge*	*3,672,400*	*$ 0.002010*	*$ 7,382*	*1.5%*	*$ -*	*$ -*	*0.0%*	*$ (7,382)*	*-100.0%*
28	*Distribution Relability Request*	*3,672,400*	*$ -*	*$ -*	*0.0%*	*$ 0.004594*	*$ 16,871*	*4.7%*	*$ 16,871*	*#DIV/0!*
29	*Federal Tax Cut Adjustment*	*$339,706*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
30	*Subtotal Rate Schedule Riders*			*$ 149,784*	*30.6%*		*$ 148,633*	*41.0%*	*$ (1,151)*	*-0.8%*
31	*Total Private Outdoor Area Revenues (rate schedule + riders)*			*$ 489,490*	*100.0%*		*$ 362,263*	*100.0%*	*$ (127,227)*	*-26.0%*
							$ 40,087			

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

Revenue Distribution
-37.14%

LINE NO.	Description	Tariff Modifier	MACCS Modifier	Monthly kWh per Fixture	Annual kWh	Monthly Fixture Count	kWh	Annual Fixture Count	Present Tariff Price	Facilities Charge	Present Annual Base Revenue	Proposed Tariff Price	Facilities Charge	Proposed Annual Base Revenue
(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	MSL-528 (closed)													
2	Mercury Vapor													
3	100 Watt	284	MVOPN	42	504	23	11,592	276	$4.38		$ 1,208.88	$2.75	$ -	$ 759.00
4	175 Watt	285	MVOPN	68	816	1,372	1,119,552	16,464	$4.43		$ 72,935.52	$2.78	$ -	$ 45,769.92
5	400 Watt	287	MVENC	155	1,860	44	81,840	528	$5.68		$ 2,999.04	$3.57	$ -	$ 1,884.96
6	1000 Watt	288	MVENC	364	4,368	1	4,368	12	$8.50		$ 102.00	$5.34	$ -	$ 64.08
7														
8	Metal Halide													
9	400 Watt	282	MTHAL	156	1,872	87	162,864	1,044	$6.50		$ 6,786.00	$4.09		$ 4,269.96
10	1000 Watt	283	MTHAL	373	4,476	7	31,332	84	$9.95		$ 835.80	$6.26		$ 525.84
11														
12	High Pressure Sodium													
13	70 Watt	295	SVOPN	35	420	2	840	24	$4.65		$ 111.60	$2.92		$ 70.08
14	100 Watt	290	SVOPN	49	588	1,878	1,104,264	22,536	$4.68		$ 105,468.48	$2.94		$ 66,255.84
15	150 Watt	294	SVOPN	59	708	69	48,852	828	$4.68		$ 3,875.04	$2.94		$ 2,434.32
16	250 Watt	291	SVENC	105	1,260	1,038	1,307,880	12,456	$5.40		$ 67,262.40	$3.39		$ 42,225.84
17	400 Watt	292	SVENC	165	1,980	272	538,560	3,264	$5.98		$ 19,518.72	$3.76		$ 12,272.64
18	1000 Watt	293	SVENC	388	4,656	25	116,400	300	$9.91		$ 2,973.00	$6.23		$ 1,869.00
19														
20	Total				23,508	4,818		57,816		$ 300,621.90	$ 284,076.48		$ 300,621.90	$ 178,401.48
21														
22														
23														
24	Base Rate Revenue + Facilities Revenue										$ 584,698.38			$ 479,023.38
25	Book-to-Bill Ratio										1.05			1.05
26	Total Municipal Base Rate Revenues (A)										$ 613,962.94			$ 502,998.83
27	Municipal Street Lighting as a % of Total Class Revenues										76.7%			73.3%
28														

29	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*	*Total Revenue Change*	*Total Percent Change*
30	*Energy Cost Recovery*	*4,523,947*	*$ 0.032419*	*$ 146,662*	*18.3%*	*$ 0.032419*	*$ 146,662*	*21.4%*	*$ -*	*0.0%*
31	*Energy Efficiency Cost Rate*	*4,523,947*	*$ 0.005340*	*$ 24,158*	*3.0%*	*$ 0.003460*	*$ 15,653*	*2.3%*	*$ (8,505)*	*-35.2%*
32	*Alternate Generation Recovery*	*613,963*	*1.10%*	*$ 6,754*	*0.8%*	*$ -*	*$ -*	*0.0%*	*$ (6,754)*	*-100.0%*
33	*Environmental Compliance Surcharge*	*4,523,947*	*$ 0.002010*	*$ 9,093*	*1.1%*	*$ -*	*$ -*	*0.0%*	*$ (9,093)*	*-100.0%*
34	*Distribution Relability Request*	*4,523,947*	*$ -*	*$ -*	*0.0%*	*$ 0.004594*	*$ 20,783*	*3.0%*	*$ 20,783*	*#DIV/0!*
35	*Federal Tax Cut Adjustment*	*$613,963*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
36	*Subtotal Rate Schedule Riders*			*$ 186,666*	*23.3%*		*$ 183,098*	*26.7%*	*$ (3,569)*	*-1.9%*
37										
38	*Total Private Outdoor Area Revenues (rate schedule + riders)*			*$ 800,629*	*100.0%*		*$ 686,097*	*100.0%*	*$ (114,533)*	*-14.3%*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

Revenue Distribution
-37.14%

LINE NO.	Description	Tariff Modifier	MACCS Modifier	Monthly kWh per Fixture	Annual kWh	Monthly Fixture Count	kWh	Annual Fixture Count	Present Tariff Price	Facilities Charge	Present Annual Base Revenue	Proposed Tariff Price	Facilities Charge	Proposed Annual Base Revenue
(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	MSL-531													
2	Mercury Vapor													
3	175 Watt	508	MVOPN	68	816	174	141,984	2,088	$ 6.23		$ 13,008.24	$3.92		$ 8,184.96
4	400 Watt	509	MVENC	155	1,860	7	13,020	84	$ 7.43		$ 624.12	$4.67		$ 392.28
5														
6	Metal Halide													
7	400 Watt	510	MTHAL	156	1,872	16	29,952	192	$ 6.50		$ 1,248.00	$4.09		$ 785.28
8	1000 Watt	511		373	4,476	-	-	-	$ 9.95		$ -	$6.26		$ -
9														
10	High Pressure Sodium													
11	100 Watt	512	SVOPN	49	588	3,472	2,041,536	41,664	$ 4.68		$ 194,987.52	$2.94		$ 122,492.16
12	250 Watt	513	SVENC	105	1,260	430	541,800	5,160	$ 5.40		$ 27,864.00	$3.39		$ 17,492.40
13	400 Watt	514	SVENC	165	1,980	186	368,280	2,232	$ 5.98		$ 13,347.36	$3.76		$ 8,392.32
14	1000 Watt	515	SVENC	388	4,656	3	13,968	36	$ 9.91		$ 356.76	$6.23		$ 224.28
15														
16														
17														
18														
19														
20	Total					4,288		51,456		$ 146,960.80	$ 251,436.00		$ 146,960.80	$ 157,963.68
21														
22														
23														
24	Base Rate Revenue + Facilities Revenue										$ 398,396.80			$ 304,924.48
25	Book-to-Bill Ratio										1.05			1.05
26	Total Municipal Base Rate Revenues (A)										$ 417,504.78			$ 319,549.32
27	Municipal Street Lighting as a % of Total Class Revenues										76.5%			71.7%
28														

29	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*	*Total Revenue Change*	*Total Percent Change*
30	*Energy Cost Recovery*	*3,110,217*	*$ 0.032419*	*$ 100,830*	*18.5%*	*$ 0.032419*	*$ 100,830*	*22.6%*	*$ -*	*0.0%*
31	*Energy Efficiency Cost Rate*	*3,110,217*	*$ 0.005340*	*$ 16,609*	*3.0%*	*$ 0.003460*	*$ 10,761*	*2.4%*	*$ (5,847)*	*-35.2%*
32	*Alternate Generation Recovery*	*417,505*	*1.10%*	*$ 4,593*	*0.8%*	*$ -*	*$ -*	*0.0%*	*$ (4,593)*	*-100.0%*
33	*Environmental Compliance Surcharge*	*3,110,217*	*$ 0.002010*	*$ 6,252*	*1.1%*	*$ -*	*$ -*	*0.0%*	*$ (6,252)*	*-100.0%*
34	*Distribution Relability Request*	*3,110,217*	*$ -*	*$ -*	*0.0%*	*$ 0.004594*	*$ 14,288*	*3.2%*	*$ 14,288*	*#DIV/0!*
35	*Federal Tax Cut Adjustment*	*$417,505*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
36	*Subtotal Rate Schedule Riders*			*$ 128,283*	*23.5%*		*$ 125,880*	*28.3%*	*$ (2,403)*	*-1.9%*
37										
38	*Total Private Outdoor Area Revenues (rate schedule + riders)*			*$ 545,788*	*100.0%*		*$ 445,429*	*100.0%*	*$ (100,358)*	*-18.4%*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

Revenue Distribution
-24.38%

LINE NO.	Description	Tariff Modifier	MACCS Modifier	Monthly kWh per Fixture	Annual kWh	Monthly Fixture Count	kWh	Annual Fixture Count	Present Tariff Price	Facilities Charge	Present Annual Base Revenue	Proposed Tariff Price	Facilities Charge	Proposed Annual Base Revenue
(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	Public Street & Highway Lighting 534 - energy only													
2	Mercury Vapor													
3	175 Watt	255	MVOPN	68	816	45	36,720	540	$ 3.75		$ 2,025.00	$2.84		$ 1,531.40
4	400 Watt	251		155	1,860	-	-	-	$ 5.36		$ -	$4.05		$ -
5	1000 Watt	253		201	2,412	-	-	-	$ 6.21		$ -	$4.70		$ -
6														
7	Metal Halide													
8	400 Watt	256	MTHAL	156	1,872	2	3,744	24	$ 5.38		$ 129.12	$4.07		$ 97.65
9	1000 Watt	257		373	4,476	-	-	-	$ 9.38		$ -	$7.09		$ -
10														
11	High Pressure Sodium													
12	70 Watt	258	SVOPN	35	420	9	3,780	108	$ 3.15		$ 340.20	$2.38		$ 257.27
13	100 Watt	259	SVOPN	49	588	67	39,396	804	$ 3.40		$ 2,733.60	$2.57		$ 2,067.27
14	250 Watt	261		105	1,260	-	-	-	$ 4.44		$ -	$3.36		$ -
15	400 Watt	262		165	1,980	-	-	-	$ 5.54		$ -	$4.19		$ -
16	1000 Watt	263		388	4,656	-	-	-	$ 9.65		$ -	$7.30		$ -
17														
18	Total													
19														
20														
21	Total					123		1,476		$ 138.24	$ 5,227.92		$ 138.24	$ 3,953.59
22														
23														
24														
25	Base Rate Revenue + Facilities Revenue										$ 5,366.16			$ 4,091.83
26	Book-to-Bill Ratio										1.11			1.11
27	Total Municipal Base Rate Revenues (A)										$ 5,969.90			$ 4,552.20
28	Municipal Street Lighting as a % of Total Class Revenues										63.8%			57.3%
29														

LINE NO.	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*	*Total Revenue Change*	*Total Percent Change*
30										
31	*Energy Cost Recovery*	*83,657*	*$ 0.032419*	*$ 2,712*	*29.0%*	*$ 0.032419*	*$ 2,712*	*34.2%*	*$ -*	*0.0%*
32	*Energy Efficiency Cost Rate*	*83,657*	*$ 0.005340*	*$ 447*	*4.8%*	*$ 0.003460*	*$ 289*	*3.6%*	*$ (157)*	*-35.2%*
33	*Alternate Generation Recovery*	*5,970*	*1.10%*	*$ 66*	*0.7%*	*$ -*	*$ -*	*0.0%*	*$ (66)*	*-100.0%*
34	*Environmental Compliance Surcharge*	*83,657*	*$ 0.002010*	*$ 168*	*1.8%*	*$ -*	*$ -*	*0.0%*	*$ (168)*	*-100.0%*
35	*Distribution Relability Request*	*83,657*	*$ -*	*$ -*	*0.0%*	*$ 0.004594*	*$ 384*	*4.8%*	*$ 384*	*#DIV/0!*
36	*Federal Tax Cut Adjustment*	*$5,970*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
37	*Subtotal Rate Schedule Riders*			*$ 3,393*	*36.2%*		*$ 3,386*	*42.7%*	*$ (7)*	*-0.2%*
38										
39	*Total Private Outdoor Area Revenues (rate schedule + riders)*			*$ 9,363*	*100.0%*		*$ 7,938*	*100.0%*	*$ (1,424)*	*-15.2%*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

Revenue Distribution
-24.38%

LINE NO.	Description	Tariff Modifier	MACCS Modifier	Monthly kWh per Fixture	Annual kWh	Monthly Fixture Count	kWh	Annual Fixture Count	Present Tariff Price	Facilities Charge	Present Annual Base Revenue	Proposed Tariff Price	Facilities Charge	Proposed Annual Base Revenue
(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	Public Street & Highway Lighting 535 - closed													
2	Mercury Vapor													
3	175 Watt	051	MVOPN	68	816	1	816	12	$ 3.99		$ 47.88	$3.02		$ 36.21
4	400 Watt	074		155	1,860	-	-	-	$ 5.90		$ -	$4.46		$ -
5														
6	Metal Halide													
7	400 Watt	052		156	1,872	-	-	-	$ 5.93		$ -	$4.48		$ -
8	1000 Watt	053	MTHAL	373	4,476	2	8,952	24	$ 9.59		$ 230.16	$7.25		$ 174.06
9														
10	High Pressure Sodium													
11	100 Watt	055	SVOPN	49	588	31	18,228	372	$ 3.58		$ 1,331.76	$2.71		$ 1,007.14
12	250 Watt	057	SVENC	105	1,260	19	23,940	228	$ 4.81		$ 1,096.68	$3.64		$ 829.36
13	400 Watt	058	SVENC	165	1,980	1	1,980	12	$ 5.80		$ 69.60	$4.39		$ 52.63
14	1000 Watt	059	SVENC	388	4,656	-	-	-	$ 9.87		$ -	$7.46		$ -
15														
16	Total													
17														
18														
19	Total				17,508	54		648		$ 1,840.20	$ 2,776.08		$ 1,840.20	$ 2,099.40
20														
21														
22														
23	Base Rate Revenue + Facilities Revenue										$ 4,616.28			$ 3,939.60
24	Book-to-Bill Ratio										1.10			1.10
25	Total Municipal Base Rate Revenues (A)										$ 5,089.68			$ 4,343.61
26	Municipal Street Lighting as a % of Total Class Revenues										69.8%			66.6%
27														

28	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*	*Total Revenue Change*	*Total Percent Change*
29	*Energy Cost Recovery*	*53,927*	*$ 0.032419*	*$ 1,748*	*24.0%*	*$ 0.032419*	*$ 1,748*	*26.8%*	*$ -*	*0.0%*
30	*Energy Efficiency Cost Rate*	*53,927*	*$ 0.005340*	*$ 288*	*4.0%*	*$ 0.003460*	*$ 187*	*2.9%*	*$ (101)*	*-35.2%*
31	*Alternate Generation Recovery*	*5,090*	*1.10%*	*$ 56*	*0.8%*	*$ -*	*$ -*	*0.0%*	*$ (56)*	*-100.0%*
32	*Environmental Compliance Surcharge*	*53,927*	*$ 0.002010*	*$ 108*	*1.5%*	*$ -*	*$ -*	*0.0%*	*$ (108)*	*-100.0%*
33	*Distribution Relability Request*	*53,927*	*$ -*	*$ -*	*0.0%*	*$ 0.004594*	*$ 248*	*3.8%*	*$ 248*	*#DIV/0!*
34	*Federal Tax Cut Adjustment*	*$5,090*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
35	*Subtotal Rate Schedule Riders*			*$ 2,201*	*30.2%*		*$ 2,183*	*33.4%*	*$ (18)*	*-0.8%*
36										
37	*Total Private Outdoor Area Revenues (rate schedule + riders)*			*$ 7,290*	*100.0%*		*$ 6,526*	*100.0%*	*$ (764)*	*-10.5%*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

Revenue Distribution
-24.38%

LINE NO.	Description	Tariff Modifier	MACCS Modifier	Monthly kWh per Fixture	Annual kWh	Monthly Fixture Count	kWh	Annual Fixture Count	Present Tariff Price	Facilities Charge	Present Annual Base Revenue	Proposed Tariff Price	Facilities Charge	Proposed Annual Base Revenue
(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	Public Street & Highway Lighting 536 - energy only													
2	Mercury Vapor													
3	175 Watt	265	MVOPN	68	816	20	16,320	240	$ 3.75		$ 900.00	$2.84		$ 680.62
4	400 Watt	266		155	1,860	-	-	-	$ 5.36		$ -	$4.05		$ -
5														
6	Metal Halide													
7	400 Watt	267	MTHAL	156	1,872	45	84,240	540	$ 5.38		$ 2,905.20	$4.07		$ 2,197.05
8	1000 Watt	268		373	4,476	-	-	-	$ 9.38		$ -	$7.09		$ -
9														
10	High Pressure Sodium													
11	100 Watt	269	SVOPN	49	588	19	11,172	228	$ 3.40		$ 775.20	$2.57		$ 586.24
12	250 Watt	270		105	1,260	-	-	-	$ 4.44		$ -	$3.36		$ -
13	400 Watt	271		165	1,980	-	-	-	$ 5.54		$ -	$4.19		$ -
14	1000 Watt	272		388	4,656	-	-	-	$ 9.65		$ -	$7.30		$ -
15														
16	Total													
17														
18														
19	Total				17,508	84		1,008		$ -	$ 4,580.40		$ -	$ 3,463.91
20														
21														
22														
23	Base Rate Revenue + Facilities Revenue										$ 4,580.40			$ 3,463.91
24	Book-to-Bill Ratio										1.05			1.05
25	Total Municipal Base Rate Revenues (A)										$ 4,826.86			$ 3,650.29
26	Municipal Street Lighting as a % of Total Class Revenues										51.8%			44.7%
27														

28	*Riders & Requests - Adjusted Test Year*	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*	*Total Revenue Change*	*Total Percent Change*
29	*Energy Cost Recovery*	*111,755*	*$ 0.032419*	*$ 3,623*	*38.9%*	*$ 0.032419*	*$ 3,623*	*44.3%*	*$ -*	*0.0%*
30	*Energy Efficiency Cost Rate*	*111,755*	*$ 0.005340*	*$ 597*	*6.4%*	*$ 0.003460*	*$ 387*	*4.7%*	*$ (210)*	*-35.2%*
31	*Alternate Generation Recovery*	*4,827*	*1.10%*	*$ 53*	*0.6%*	*$ -*	*$ -*	*0.0%*	*$ (53)*	*-100.0%*
32	*Environmental Compliance Surcharge*	*111,755*	*$ 0.002010*	*$ 225*	*2.4%*	*$ -*	*$ -*	*0.0%*	*$ (225)*	*-100.0%*
33	*Distribution Relability Request*	*111,755*	*$ -*	*$ -*	*0.0%*	*$ 0.004594*	*$ 513*	*6.3%*	*$ 513*	*#DIV/0!*
34	*Federal Tax Cut Adjustment*	*$4,827*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
35	*Subtotal Rate Schedule Riders*			*$ 4,497*	*48.2%*		*$ 4,523*	*55.3%*	*$ 26*	*0.6%*
36										
37	*Total Private Outdoor Area Revenues (rate schedule + riders)*			*$ 9,324*	*100.0%*		*$ 8,173*	*100.0%*	*$ (1,151)*	*-12.3%*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule comparing Arkansas retail revenues for each rate schedule by detailed rate component for the pro forma year, at present and proposed rates.

Revenue Distribution
-24.38%

LINE NO.	Description	Tariff Modifier	MACCS Modifier	Monthly kWh per Fixture	Annual kWh	Monthly Fixture Count	kWh	Annual Fixture Count	Present Tariff Price	Facilities Charge	Present Annual Base Revenue	Proposed Tariff Price	Facilities Charge	Proposed Annual Base Revenue
(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	Public Street & Highway Lighting 537													
2	Mercury Vapor													
3	175 Watt	500	MVOPN	68	816	23	18,768	276	$ 3.99		$ 1,101.24	$3.02		$ 832.81
4	400 Watt	501		155	1,860	-	-	-	$ 5.90		$ -	$4.46		$ -
5														
6	Metal Halide													
7	400 Watt	502		156	1,872	-	-	-	$ 5.93		$ -	$4.48		$ -
8	1000 Watt	503		373	4,476	-	-	-	$ 9.59		$ -	$7.25		$ -
9														
10	High Pressure Sodium													
11	100 Watt	504	SVOPN	49	588	19	11,172	228	$ 3.58		$ 816.24	$2.71		$ 617.28
12	250 Watt	505		105	1,260	-	-	-	$ 4.81		$ -	$3.64		$ -
13	400 Watt	506		165	1,980	-	-	-	$ 5.80		$ -	$4.39		$ -
14	1000 Watt	507		388	4,656	-	-	-	$ 9.87		$ -	$7.46		$ -
15														
16	Total													
17														
18														
19	Total				17,508	42		504		$ -	$ 1,917.48		$ -	$ 1,450.09
20														
21														
22														
23	Base Rate Revenue + Facilities Revenue										$ 1,917.48			$ 1,450.09
24	Book-to-Bill Ratio										0.81			0.81
25	Total Municipal Base Rate Revenues (A)										$ 1,554.31			$ 1,175.44
26	Municipal Street Lighting as a % of Total Class Revenues										56.2%			49.1%
27														

	Riders & Requests - Adjusted Test Year	*Adjusted TY Unit*	*Present Factor*	*Present Factor $*	*% of Rider Revenues*	*Proposed Factor*	*Proposed Factor $*	*% of Rider Revenues*	*Total Revenue Change*	*Total Percent Change*
28										
29	*Energy Cost Recovery*	*30,077*	*$ 0.032419*	*$ 975*	*35.2%*	*$ 0.032419*	*$ 975*	*40.8%*	*$ -*	*0.0%*
30	*Energy Efficiency Cost Rate*	*30,077*	*$ 0.005340*	*$ 161*	*5.8%*	*$ 0.003460*	*$ 104*	*4.3%*	*$ (57)*	*-35.2%*
31	*Alternate Generation Recovery*	*1,554*	*1.10%*	*$ 17*	*0.6%*	*$ -*	*$ -*	*0.0%*	*$ (17)*	*-100.0%*
32	*Environmental Compliance Surcharge*	*30,077*	*$ 0.002010*	*$ 60*	*2.2%*	*$ -*	*$ -*	*0.0%*	*$ (60)*	*-100.0%*
33	*Distribution Relability Request*	*30,077*	*$ -*	*$ -*	*0.0%*	*$ 0.004594*	*$ 138*	*5.8%*	*$ 138*	*#DIV/0!*
34	*Federal Tax Cut Adjustment*	*$1,554*	*0.00%*	*$ -*	*0.0%*	*0.00%*	*$ -*	*0.0%*	*$ -*	*#DIV/0!*
35	*Subtotal Rate Schedule Riders*			*$ 1,213*	*43.8%*		*$ 1,217*	*50.9%*	*$ 4*	*0.3%*
36										
37	*Total Private Outdoor Area Revenues (rate schedule + riders)*			*$ 2,768*	*100.0%*		*$ 2,393*	*100.0%*	*$ (375)*	*-13.5%*

Supporting Schedules
(a) E-11.2 & supporting workpapers

Recap Schedules
(A) H-1

Explanation: Schedule(s) comparing annual or seasonal analysis of customer bills at varying levels of usage at present and proposed rates by rate schedule. For each rate schedule, applicant should order bills by usage level in ascending order and separate into 10 groups (deciles) of equal number of bills. For each group, company should calculate a present and proposed bill using rates from Schedule H-2 applied to that group's average usage. A company with uniform monthly rates will provide an annual analysis. A company with seasonal rates will provide a seasonal analysis for each season. (Exclude non-standard rates, such as lighting, variable peak pricing, and special contracts).

Time Period: On-Peak Season
(Annual or separate seasonal schedule for each season)

Rate Schedule: Standard Residential

Description:____________________

(1) Line No.	(2) Decile Levels for Numbers of Bills	(3) Number of Bills	(4) Average Usage	(5) Average Billed Demand	(6) Average Bill at Present Rates (Col. 4) x (Sch H-2 Col. 4)	(7) Average Bill at Proposed Rates (Col. 4) x (Sch H-2 Col. 7)	(8) Proposed Change Revenue $ (Col. 7 - Col. 6)	(9) Proposed Change % (Col. 8 / Col. 6)
1	**1**	47,052	22		$ 8.72	$ 11.54	$ 2.82	32%
2	**2**	47,053	239		$ 18.31	$ 26.78	$ 8.46	46%
3	**3**	47,053	443		$ 27.33	$ 41.10	$ 13.77	50%
4	**4**	47,053	610		$ 34.71	$ 52.82	$ 18.11	52%
5	**5**	47,053	773		$ 41.92	$ 64.26	$ 22.35	53%
6	**6**	47,053	944		$ 49.47	$ 76.27	$ 26.79	54%
7	**7**	47,053	1,137		$ 58.01	$ 89.82	$ 31.81	55%
8	**8**	47,053	1,370		$ 68.30	$ 106.17	$ 37.87	55%
9	**9**	47,053	1,705		$ 85.00	$ 134.14	$ 49.14	58%
10	**10**	47,046	2,639		$ 134.87	$ 219.97	$ 85.10	63%
11								
12	**Total Bills**	470,522						

Time Period: Off-Peak Season
(Annual or separate seasonal schedule for each season)

Rate Schedule: Standard Residential

Description:____________________

(1) Line No.	(2) Decile Levels for Numbers of Bills	(3) Number of Bills	(4) Average Usage	(5) Average Billed Demand	(6) Average Bill at Present Rates (Col. 4) x (Sch H-2 Col. 4)	(7) Average Bill at Proposed Rates (Col. 4) x (Sch H-2 Col. 7)	(8) Proposed Change Revenue $ (Col. 7 - Col. 6)	(9) Proposed Change % (Col. 8 / Col. 6)
1	**1**	65,102	25		$ 8.65	$ 11.53	$ 2.88	33%
2	**2**	65,103	211		$ 15.30	$ 22.87	$ 7.57	49%
3	**3**	65,103	355		$ 20.46	$ 31.66	$ 11.20	55%
4	**4**	65,103	466		$ 24.43	$ 38.43	$ 13.99	57%
5	**5**	65,103	577		$ 28.41	$ 45.20	$ 16.79	59%
6	**6**	65,103	700		$ 32.81	$ 52.70	$ 19.89	61%
7	**7**	65,103	850		$ 38.18	$ 61.85	$ 23.67	62%
8	**8**	65,103	1,053		$ 45.45	$ 74.23	$ 28.79	63%
9	**9**	65,103	1,382		$ 57.23	$ 94.30	$ 37.08	65%
10	**10**	65,092	2,460		$ 95.82	$ 160.06	$ 64.24	67%
11								
12	**Total Bills**	651,018						

Supporting Schedules
As needed

Southwestern Electric Power Company
Docket No. 19-008-U
Test Year Ending December 31, 2018

Explanation: Schedule(s) comparing annual or seasonal analysis of customer bills at varying levels of usage at present and proposed rates by rate schedule. For each rate schedule, applicant should order bills by usage level in ascending order and separate into 10 groups (deciles) of equal number of bills. For each group, company should calculate a present and proposed bill using rates from Schedule H-2 applied to that group's average usage. A company with uniform monthly rates will provide an annual analysis. A company with seasonal rates will provide a seasonal analysis for each season. (Exclude non-standard rates, such as lighting, variable peak pricing, and special contracts).

Time Period: On-Peak Season
(Annual or separate seasonal schedule for each season)

Rate Schedule: Standard Residential

Description:______________________________

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		
Line No.	Decile Levels for Numbers of Bills	Number of Bills	Average Usage	Average Billed Demand	Average Bill at Present Rates (Col. 4) x (Sch H-2 Col. 4)	Average Bill at Proposed Rates (Col. 4) x (Sch H-2 Col. 7)	Proposed Change Revenue $ (Col. 7 - Col. 6)	Proposed Change % (Col. 8 / Col. 6)		
1	**1**	6,600	106		$ 12.44	$ 17.44	$ 5.01	40%	7.75	10.00
2	**2**	6,601	394		$ 25.16	$ 37.66	$ 12.49	50%	4.69	7.44
3	**3**	6,600	595		$ 34.05	$ 51.77	$ 17.72	52%	12.44	17.44
4	**4**	6,600	782		$ 42.31	$ 64.90	$ 22.58	53%		
5	**5**	6,600	964		$ 50.36	$ 77.67	$ 27.31	54%		
6	**6**	6,600	1,153		$ 58.71	$ 90.94	$ 32.23	55%		
7	**7**	6,600	1,361		$ 67.91	$ 105.54	$ 37.64	55%		
8	**8**	6,600	1,612		$ 80.03	$ 125.59	$ 45.56	57%		
9	**9**	6,600	1,977		$ 99.52	$ 159.14	$ 59.61	60%		
10	**10**	6,588	3,081		$ 158.48	$ 260.59	$ 102.12	64%	7.75	10.00
11									66.30	105.30
12	**Total Bills**	65,989							84.43	145.29
									158.48	260.59

Time Period: Off-Peak Season
(Annual or separate seasonal schedule for each season)

Rate Schedule: Standard Residential

Description:______________________________

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.	Decile Levels for Numbers of Bills	Number of Bills	Average Usage	Average Billed Demand	Average Bill at Present Rates (Col. 4) x (Sch H-2 Col. 4)	Average Bill at Proposed Rates (Col. 4) x (Sch H-2 Col. 7)	Proposed Change Revenue $ (Col. 7 - Col. 6)	Proposed Change % (Col. 8 / Col. 6)
1	**1**	9,320	118		$ 11.97	$ 17.20	$ 5.22	44%
2	**2**	9,321	415		$ 22.61	$ 35.32	$ 12.71	56%
3	**3**	9,321	610		$ 28.18	$ 44.68	$ 16.50	59%
4	**4**	9,321	790		$ 32.32	$ 51.53	$ 19.21	59%
5	**5**	9,321	972		$ 36.51	$ 58.45	$ 21.94	60%
6	**6**	9,321	1,172		$ 41.11	$ 66.05	$ 24.94	61%
7	**7**	9,321	1,413		$ 46.65	$ 75.21	$ 28.56	61%
8	**8**	9,321	1,740		$ 54.17	$ 87.64	$ 33.47	62%
9	**9**	9,318	2,258		$ 66.08	$ 107.34	$ 41.26	62%
10	**10**	9,318	3,769		$ 100.84	$ 164.79	$ 63.95	63%
11								
12	**Total Bills**	93,203						

Supporting Schedules
As needed

Southwestern Electric Power Company
Docket No. 19-008-U
Test Year Ending December 31, 2018

Explanation: Schedule(s) comparing annual or seasonal analysis of customer bills at varying levels of usage at present and proposed rates by rate schedule. For each rate schedule, applicant should order bills by usage level in ascending order and separate into 10 groups (deciles) of equal number of bills. For each group, company should calculate a present and proposed bill using rates from Schedule H-2 applied to that group's average usage. A company with uniform monthly rates will provide an annual analysis. A company with seasonal rates will provide a seasonal analysis for each season. (Exclude non-standard rates, such as lighting, variable peak pricing, and special contracts).

Time Period: On-Peak Season
(Annual or separate seasonal schedule for each season)

Rate Schedule: General Service

Description:____

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.	Decile Levels for Numbers of Bills	Number of Bills	Average Usage	Average Billed Demand	Average Bill at Present Rates (Col. 4) x (Sch H-2 Col. 4)	Average Bill at Proposed Rates (Col. 4) x (Sch H-2 Col. 7)	Proposed Change Revenue $ (Col. 7 - Col. 6)	Proposed Change % (Col. 8 / Col. 6)
1	**1**	8,205	7	-	$ 8.81	$ 10.92	$ 2.10	24%
2	**2**	8,151	100	0.19	$ 12.47	$ 16.40	$ 3.93	32%
3	**3**	8,150	272	0.30	$ 18.21	$ 24.96	$ 6.75	37%
4	**4**	8,151	473	0.58	$ 25.56	$ 35.94	$ 10.39	41%
5	**5**	8,151	774	1.30	$ 37.84	$ 54.38	$ 16.54	44%
6	**6**	8,151	1,212	2.48	$ 56.22	$ 82.01	$ 25.79	46%
7	**7**	8,151	1,833	4.60	$ 84.19	$ 124.13	$ 39.94	47%
8	**8**	8,151	2,814	7.88	$ 128.09	$ 190.22	$ 62.13	49%
9	**9**	8,151	4,726	13.32	$ 209.63	$ 312.82	$ 103.19	49%
10	**10**	8,072	10,127	26.53	$ 430.92	$ 645.10	$ 214.18	50%
11								
12	**Total Bills**	81,484						

Time Period: Off-Peak Season
(Annual or separate seasonal schedule for each season)

Rate Schedule: General Service

Description:____

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.	Decile Levels for Numbers of Bills	Number of Bills	Average Usage	Average Billed Demand	Average Bill at Present Rates (Col. 4) x (Sch H-2 Col. 4)	Average Bill at Proposed Rates (Col. 4) x (Sch H-2 Col. 7)	Proposed Change Revenue $ (Col. 7 - Col. 6)	Proposed Change % (Col. 8 / Col. 6)
1	**1**	11,425	7	0.05	$ 8.99	$ 11.19	$ 2.20	24%
2	**2**	11,426	96	0.15	$ 11.65	$ 15.16	$ 3.51	30%
3	**3**	11,426	252	0.31	$ 16.25	$ 22.02	$ 5.77	35%
4	**4**	11,426	420	0.47	$ 21.16	$ 29.33	$ 8.17	39%
5	**5**	11,426	636	0.99	$ 28.79	$ 40.77	$ 11.98	42%
6	**6**	11,425	958	2.05	$ 41.35	$ 59.68	$ 18.33	44%
7	**7**	11,425	1,443	3.68	$ 60.42	$ 88.38	$ 27.96	46%
8	**8**	11,426	2,219	6.37	$ 91.27	$ 134.84	$ 43.56	48%
9	**9**	11,425	3,652	10.83	$ 146.12	$ 217.32	$ 71.21	49%
10	**10**	11,426	7,842	20.67	$ 293.03	$ 437.67	$ 144.64	49%
11								
12	**Total Bills**	114,256						

Supporting Schedules
As needed

Explanation: Schedule(s) comparing annual or seasonal analysis of customer bills at varying levels of usage at present and proposed rates by rate schedule. For each rate schedule, applicant should order bills by usage level in ascending order and separate into 10 groups (deciles) of equal number of bills. For each group, company should calculate a present and proposed bill using rates from Schedule H-2 applied to that group's average usage. A company with uniform monthly rates will provide an annual analysis. A company with seasonal rates will provide a seasonal analysis for each season. (Exclude non-standard rates, such as lighting, variable peak pricing, and special contracts).

Time Period: On-Peak Season
(Annual or separate seasonal schedule for each season)

Rate Schedule: Lighting & Power Service - Secondary

Description:

(1) Line No.	(2) Decile Levels for Numbers of Bills	(3) Number of Bills	(4) Average Usage	(5) Average Billed Demand	(6) Average Bill at Present Rates (Col. 4) x (Sch H-2 Col. 4)	(7) Average Bill at Proposed Rates (Col. 4) x (Sch H-2 Col. 7)	(8) Proposed Change Revenue $ (Col. 7 - Col. 6)	(9) Proposed Change % (Col. 8 / Col. 6)
1	**1**	810	7,168	56.24	$ 539.30	$ 909.47	$ 370.17	69%
2	**2**	811	13,794	61.90	$ 688.05	$ 1,160.43	$ 472.38	69%
3	**3**	811	17,406	62.99	$ 754.07	$ 1,271.82	$ 517.75	69%
4	**4**	811	21,021	67.13	$ 843.17	$ 1,422.13	$ 578.96	69%
5	**5**	811	25,106	79.91	$ 1,005.02	$ 1,695.12	$ 690.10	69%
6	**6**	811	30,521	97.49	$ 1,224.39	$ 2,065.11	$ 840.73	69%
7	**7**	811	39,064	121.26	$ 1,540.54	$ 2,598.37	$ 1,057.83	69%
8	**8**	811	51,848	148.82	$ 1,953.16	$ 3,294.37	$ 1,341.22	69%
9	**9**	811	82,121	233.43	$ 3,076.33	$ 5,188.83	$ 2,112.50	69%
10	**10**	813	320,402	707.73	$ 10,469.79	$ 17,660.26	$ 7,190.46	69%
11								
12	**Total Bills**	8,111						

Time Period: Off-Peak Season
(Annual or separate seasonal schedule for each season)

Rate Schedule: Lighting & Power Service - Secondary

Description:

(1) Line No.	(2) Decile Levels for Numbers of Bills	(3) Number of Bills	(4) Average Usage	(5) Average Billed Demand	(6) Average Bill at Present Rates (Col. 4) x (Sch H-2 Col. 4)	(7) Average Bill at Proposed Rates (Col. 4) x (Sch H-2 Col. 7)	(8) Proposed Change Revenue $ (Col. 7 - Col. 6)	(9) Proposed Change % (Col. 8 / Col. 6)
1	**1**	1,150	5,462	54.04	$ 355.32	$ 595.44	$ 240.12	68%
2	**2**	1,151	10,330	58.76	$ 406.99	$ 682.13	$ 275.15	68%
3	**3**	1,140	13,235	53.18	$ 386.60	$ 648.06	$ 261.45	68%
4	**4**	1,140	16,232	64.66	$ 470.72	$ 789.06	$ 318.34	68%
5	**5**	1,141	19,693	70.96	$ 525.41	$ 880.79	$ 355.37	68%
6	**6**	1,140	24,365	86.44	$ 641.80	$ 1,075.90	$ 434.10	68%
7	**7**	1,140	31,801	109.36	$ 816.56	$ 1,368.89	$ 552.33	68%
8	**8**	1,140	44,271	141.71	$ 1,072.50	$ 1,798.02	$ 725.51	68%
9	**9**	1,140	70,325	207.77	$ 1,597.92	$ 2,678.98	$ 1,081.05	68%
10	**10**	1,101	285,902	674.29	$ 5,456.91	$ 9,149.87	$ 3,692.96	68%
11								
12	**Total Bills**	11,383						

Supporting Schedules
As needed

Explanation: Schedule(s) comparing annual or seasonal analysis of customer bills at varying levels of usage at present and proposed rates by rate schedule. For each rate schedule, applicant should order bills by usage level in ascending order and separate into 10 groups (deciles) of equal number of bills. For each group, company should calculate a present and proposed bill using rates from Schedule H-2 applied to that group's average usage. A company with uniform monthly rates will provide an annual analysis. A company with seasonal rates will provide a seasonal analysis for each season. (Exclude non-standard rates, such as lighting, variable peak pricing, and special contracts).

Time Period: On-Peak Season
(Annual or separate seasonal schedule for each season)

Rate Schedule: Lighting & Power Service - Primary

Description:______________________

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.	Decile Levels for Numbers of Bills	Number of Bills	Average Usage	Average Billed Demand	Average Bill at Present Rates (Col. 4) x (Sch H-2 Col. 4)	Average Bill at Proposed Rates (Col. 4) x (Sch H-2 Col. 7)	Proposed Change: Revenue $ (Col. 7 - Col. 6)	Proposed Change: % (Col. 8 / Col. 6)
1	**1**	27	24,740	95.57	$ 1,037.08	$ 1,703.17	$ 666.08	64%
2	**2**	25	63,989	279.37	$ 2,901.15	$ 4,764.22	$ 1,863.07	64%
3	**3**	25	145,018	443.86	$ 5,287.77	$ 8,684.78	$ 3,397.01	64%
4	**4**	25	333,177	887.24	$ 11,247.42	$ 18,474.19	$ 7,226.77	64%
5	**5**	25	542,280	1,349.94	$ 17,666.30	$ 29,018.24	$ 11,351.94	64%
6	**6**	25	661,632	1,561.44	$ 20,972.33	$ 34,449.46	$ 13,477.13	64%
7	**7**	25	951,408	2,053.54	$ 28,853.63	$ 47,397.28	$ 18,543.64	64%
8	**8**	25	1,480,704	2,982.90	$ 43,456.74	$ 71,387.68	$ 27,930.94	64%
9	**9**	25	2,472,480	5,036.56	$ 72,942.95	$ 119,824.96	$ 46,882.02	64%
10	**10**	17	4,686,141	9,116.25	$ 135,328.63	$ 222,311.80	$ 86,983.17	64%
11								
12	**Total Bills**	244						

Time Period: Off-Peak Season
(Annual or separate seasonal schedule for each season)

Rate Schedule: Lighting & Power Service - Primary

Description:______________________

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.	Decile Levels for Numbers of Bills	Number of Bills	Average Usage	Average Billed Demand	Average Bill at Present Rates (Col. 4) x (Sch H-2 Col. 4)	Average Bill at Proposed Rates (Col. 4) x (Sch H-2 Col. 7)	Proposed Change: Revenue $ (Col. 7 - Col. 6)	Proposed Change: % (Col. 8 / Col. 6)
1	**1**	32	20,483	104.36	$ 650.49	$ 1,069.93	$ 419.44	64%
2	**2**	34	47,832	199.25	$ 1,281.25	$ 2,107.39	$ 826.14	64%
3	**3**	34	108,249	365.54	$ 2,442.78	$ 4,017.83	$ 1,575.05	64%
4	**4**	34	226,030	604.59	$ 4,251.68	$ 6,993.00	$ 2,741.32	64%
5	**5**	34	409,232	1,209.83	$ 8,314.13	$ 13,674.82	$ 5,360.68	64%
6	**6**	34	549,000	1,231.31	$ 9,058.02	$ 14,898.14	$ 5,840.13	64%
7	**7**	34	738,988	1,770.06	$ 12,795.28	$ 21,045.06	$ 8,249.78	64%
8	**8**	34	1,166,082	2,210.96	$ 17,076.02	$ 28,085.47	$ 11,009.46	64%
9	**9**	34	1,916,153	4,108.98	$ 30,605.74	$ 50,338.58	$ 19,732.83	64%
10	**10**	32	3,852,019	7,758.31	$ 58,841.04	$ 96,778.06	$ 37,937.02	64%
11								
12	**Total Bills**	336						

Supporting Schedules
As needed

Explanation: Schedule(s) comparing annual or seasonal analysis of customer bills at varying levels of usage at present and proposed rates by rate schedule. For each rate schedule, applicant should order bills by usage level in ascending order and separate into 10 groups (deciles) of equal number of bills. For each group, company should calculate a present and proposed bill using rates from Schedule H-2 applied to that group's average usage. A company with uniform monthly rates will provide an annual analysis. A company with seasonal rates will provide a seasonal analysis for each season. (Exclude non-standard rates, such as lighting, variable peak pricing, and special contracts).

Time Period: On-Peak Season
(Annual or separate seasonal schedule for each season)

Rate Schedule: Municipal Service

Description:______________________________

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.	Decile Levels for Numbers of Bills	Number of Bills	Average Usage	Average Billed Demand	Average Bill at Present Rates (Col. 4) x (Sch H-2 Col. 4)	Average Bill at Proposed Rates (Col. 4) x (Sch H-2 Col. 7)	Proposed Change Revenue $ (Col. 7 - Col. 6)	Proposed Change % (Col. 8 / Col. 6)
1	**1**	240	0	0.85	$ 5.35	$ 7.36	$ 2.01	38%
2	**2**	240	2	1.17	$ 5.43	$ 7.47	$ 2.04	38%
3	**3**	240	13	0.43	$ 5.88	$ 8.08	$ 2.21	38%
4	**4**	240	48	0.64	$ 7.29	$ 10.03	$ 2.74	38%
5	**5**	241	103	0.42	$ 9.52	$ 13.10	$ 3.58	38%
6	**6**	241	175	1.03	$ 12.44	$ 17.11	$ 4.67	38%
7	**7**	241	310	1.25	$ 17.91	$ 24.63	$ 6.72	38%
8	**8**	240	515	2.67	$ 26.21	$ 36.05	$ 9.84	38%
9	**9**	240	1,355	10.77	$ 60.23	$ 82.83	$ 22.61	38%
10	**10**	243	7,749	34.18	$ 319.18	$ 438.98	$ 119.79	38%
11								
12	**Total Bills**	2,406						

Time Period: Off-Peak Season
(Annual or separate seasonal schedule for each season)

Rate Schedule: Municipal Service

Description:______________________________

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.	Decile Levels for Numbers of Bills	Number of Bills	Average Usage	Average Billed Demand	Average Bill at Present Rates (Col. 4) x (Sch H-2 Col. 4)	Average Bill at Proposed Rates (Col. 4) x (Sch H-2 Col. 7)	Proposed Change Revenue $ (Col. 7 - Col. 6)	Proposed Change % (Col. 8 / Col. 6)
1	**1**	338	0	1.65	$ 5.35	$ 7.36	$ 2.01	38%
2	**2**	335	3	1.54	$ 5.46	$ 7.51	$ 2.05	38%
3	**3**	335	13	0.23	$ 5.82	$ 8.00	$ 2.19	38%
4	**4**	335	48	0.59	$ 7.07	$ 9.73	$ 2.66	38%
5	**5**	335	108	0.92	$ 9.23	$ 12.70	$ 3.47	38%
6	**6**	335	196	1.92	$ 12.39	$ 17.04	$ 4.66	38%
7	**7**	335	333	2.59	$ 17.30	$ 23.81	$ 6.51	38%
8	**8**	335	598	3.13	$ 26.82	$ 36.90	$ 10.08	38%
9	**9**	335	1,467	10.19	$ 58.02	$ 79.83	$ 21.81	38%
10	**10**	339	6,902	31.59	$ 253.13	$ 348.32	$ 95.19	38%
11								
12	**Total Bills**	3,357						

Supporting Schedules
As needed

Explanation: Schedule(s) comparing annual or seasonal analysis of customer bills at varying levels of usage at present and proposed rates by rate schedule. For each rate schedule, applicant should order bills by usage level in ascending order and separate into 10 groups (deciles) of equal number of bills. For each group, company should calculate a present and proposed bill using rates from Schedule H-2 applied to that group's average usage. A company with uniform monthly rates will provide an annual analysis. A company with seasonal rates will provide a seasonal analysis for each season. (Exclude non-standard rates, such as lighting, variable peak pricing, and special contracts).

Time Period: On-Peak Season
(Annual or separate seasonal schedule for each season)

Rate Schedule: Municipal Pumoing

Description:________________________________

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
					Average Bill	Average Bill	Proposed Change	
Line No.	Decile Levels for Numbers of Bills	Number of Bills	Average Usage	Average Billed Demand	at Present Rates (Col. 4) x (Sch H-2 Col. 4)	at Proposed Rates (Col. 4) x (Sch H-2 Col. 7)	Revenue $ (Col. 7 - Col. 6)	% (Col. 8 / Col. 6)
1	**1**	139	0	1.08	$ 5.35	$ 7.36	$ 2.01	38%
2	**2**	139	1	0.04	$ 5.39	$ 7.41	$ 2.02	38%
3	**3**	138	6	0.38	$ 5.56	$ 7.66	$ 2.09	38%
4	**4**	138	13	0.61	$ 5.82	$ 8.00	$ 2.18	38%
5	**5**	138	47	3.44	$ 7.03	$ 9.67	$ 2.64	38%
6	**6**	138	136	5.31	$ 10.22	$ 14.05	$ 3.83	38%
7	**7**	138	358	16.31	$ 18.17	$ 24.97	$ 6.81	37%
8	**8**	138	1,031	16.30	$ 42.26	$ 58.09	$ 15.83	37%
9	**9**	138	3,665	28.19	$ 136.56	$ 187.68	$ 51.12	37%
10	**10**	145	41,224	146.43	$ 1,481.17	$ 2,035.58	$ 554.41	37%
11								
12	**Total Bills**	1,389						

Time Period: Off-Peak Season
(Annual or separate seasonal schedule for each season)

Rate Schedule: Municipal Pumoing

Description:________________________________

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
					Average Bill	Average Bill	Proposed Change	
Line No.	Decile Levels for Numbers of Bills	Number of Bills	Average Usage	Average Billed Demand	at Present Rates (Col. 4) x (Sch H-2 Col. 4)	at Proposed Rates (Col. 4) x (Sch H-2 Col. 7)	Revenue $ (Col. 7 - Col. 6)	% (Col. 8 / Col. 6)
1	**1**	195	0	0.89	$ 5.35	$ 7.36	$ 2.01	38%
2	**2**	195	1	0.04	$ 5.38	$ 7.40	$ 2.02	38%
3	**3**	194	7	0.03	$ 5.57	$ 7.66	$ 2.09	38%
4	**4**	194	16	0.52	$ 5.85	$ 8.04	$ 2.20	38%
5	**5**	194	72	2.49	$ 7.58	$ 10.43	$ 2.85	38%
6	**6**	194	243	10.53	$ 12.88	$ 17.71	$ 4.83	37%
7	**7**	194	671	15.74	$ 26.15	$ 35.94	$ 9.79	37%
8	**8**	194	1,775	17.76	$ 60.38	$ 82.98	$ 22.60	37%
9	**9**	194	4,349	28.83	$ 140.17	$ 192.63	$ 52.46	37%
10	**10**	195	36,198	139.68	$ 1,127.49	$ 1,549.39	$ 421.91	37%
11								
12	**Total Bills**	1,943						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Electric Heating Appliance Service - R-3

Description: January 2018

USAGE UNIT			Specify Units		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	0	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	315	15,324	15,324	$ 2,990	315	2.31%	15,324	0.06%	$ 2,990	0.37%
3	3	100	*101-200*	221	33,205	33,205	$ 2,901	536	3.94%	48,529	0.18%	$ 5,891	0.72%
4	4	100	*201-300*	217	54,341	54,341	$ 3,627	753	5.53%	102,870	0.38%	$ 9,519	1.17%
5	5	100	*301-400*	284	100,437	100,437	$ 5,797	1,037	7.61%	203,307	0.75%	$ 15,315	1.88%
6	6	100	*401-500*	323	146,352	146,352	$ 7,743	1,360	9.99%	349,659	1.29%	$ 23,058	2.83%
7	7	100	*501-600*	442	243,269	243,269	$ 11,849	1,802	13.23%	592,928	2.18%	$ 34,907	4.29%
8	8	100	*601-700*	464	302,368	302,368	$ 13,520	2,266	16.64%	895,296	3.29%	$ 48,427	5.95%
9	9	100	*701-800*	482	362,590	362,590	$ 15,160	2,748	20.18%	1,257,886	4.63%	$ 63,587	7.81%
10	10	100	*801-900*	527	449,289	449,289	$ 17,791	3,275	24.05%	1,707,175	6.28%	$ 81,378	10.00%
11	11	100	*901-1000*	510	484,929	484,929	$ 18,370	3,785	27.79%	2,192,104	8.06%	$ 99,748	12.26%
12	12	100	*1001-1100*	472	495,465	495,465	$ 18,075	4,257	31.26%	2,687,569	9.88%	$ 117,822	14.48%
13	13	100	*1101-1200*	466	536,256	536,256	$ 18,928	4,723	34.68%	3,223,825	11.86%	$ 136,750	16.80%
14	14	100	*1201-1300*	501	627,112	627,112	$ 21,513	5,224	38.36%	3,850,937	14.16%	$ 158,263	19.45%
15	15	100	*1301-1400*	430	581,480	581,480	$ 19,459	5,654	41.51%	4,432,417	16.30%	$ 177,721	21.84%
16	16	100	1401-1500	436	632,957	632,957	$ 20,727	6,090	44.71%	5,065,374	18.63%	$ 198,449	24.38%
17	17	500	1501-2000	1,969	3,429,712	3,429,712	$ 106,745	8,059	59.17%	8,495,086	31.25%	$ 305,193	37.50%
18	18	500	2001-2500	1,598	3,581,702	3,581,702	$ 104,991	9,657	70.90%	12,076,788	44.42%	$ 410,184	50.40%
19	19	500	2501-3000	1,241	3,396,759	3,396,759	$ 95,686	10,898	80.01%	15,473,547	56.91%	$ 505,870	62.16%
20	20		over 3000	2,722	11,714,936	11,714,936	$ 307,960	13,620	100.00%	27,188,483	100.00%	$ 813,830	100.00%
21	**TOTAL**			13,620	27,188,483	27,188,483	$ 813,830						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Electric Heating Appliance Service - R-3

Description: February 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED			CUMULATIVE BILLED TOTALS						
Line No.	Block Number	Block Size	Usage	Number of Bills By Block	Metered Usage By Block	Billed Usage By Block		Revenue By Block	Bills Number	% of Total	Usage	% of Total		Revenue Amount	% of Total
1	1	-	0	0	0	0		0	0	0.00%	0	0.00%		0	0.00%
2	2	100	*1-100*	367	17,633	17,633	$	3,476	367	2.71%	17,633	0.08%	$	3,476	0.49%
3	3	100	*101-200*	272	40,321	40,321	$	3,551	639	4.72%	57,954	0.25%	$	7,027	0.99%
4	4	100	*201-300*	248	62,451	62,451	$	4,158	887	6.56%	120,405	0.53%	$	11,185	1.58%
5	5	100	*301-400*	375	132,488	132,488	$	7,649	1,262	9.33%	252,893	1.11%	$	18,834	2.65%
6	6	100	*401-500*	451	203,740	203,740	$	10,789	1,713	12.67%	456,633	2.01%	$	29,623	4.17%
7	7	100	*501-600*	538	296,185	296,185	$	14,425	2,251	16.64%	752,818	3.31%	$	44,048	6.20%
8	8	100	*601-700*	581	377,668	377,668	$	16,908	2,832	20.94%	1,130,486	4.96%	$	60,956	8.59%
9	9	100	*701-800*	641	480,645	480,645	$	20,125	3,473	25.68%	1,611,131	7.08%	$	81,081	11.42%
10	10	100	*801-900*	578	492,700	492,700	$	19,511	4,051	29.95%	2,103,831	9.24%	$	100,591	14.17%
11	11	100	*901-1000*	570	541,538	541,538	$	20,521	4,621	34.17%	2,645,369	11.62%	$	121,112	17.06%
12	12	100	*1001-1100*	576	604,813	604,813	$	22,061	5,197	38.43%	3,250,182	14.27%	$	143,173	20.17%
13	13	100	*1101-1200*	524	602,984	602,984	$	21,283	5,721	42.30%	3,853,166	16.92%	$	164,457	23.16%
14	14	100	*1201-1300*	494	616,752	616,752	$	21,175	6,215	45.96%	4,469,918	19.63%	$	185,632	26.15%
15	15	100	*1301-1400*	482	650,642	650,642	$	21,785	6,697	49.52%	5,120,560	22.49%	$	207,417	29.22%
16	16	100	1401-1500	495	717,632	717,632	$	23,510	7,192	53.18%	5,838,192	25.64%	$	230,927	32.53%
17	17	500	1501-2000	2,030	3,536,015	3,536,015	$	110,053	9,222	68.19%	9,374,207	41.17%	$	340,980	48.03%
18	18	500	2001-2500	1,519	3,405,959	3,405,959	$	99,831	10,741	79.42%	12,780,166	56.13%	$	440,811	62.09%
19	19	500	2501-3000	1,068	2,917,503	2,917,503	$	82,215	11,809	87.32%	15,697,669	68.94%	$	523,025	73.67%
20	20		over 3000	1,715	7,071,996	7,071,996	$	186,923	13,524	100.00%	22,769,665	100.00%	$	709,949	100.00%
21	**TOTAL**			13,524	22,769,665	22,769,665	$	709,949							

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Electric Heating Appliance Service - R-3

Description: March 2018

USAGE UNIT			*Specify Units*		**ACTUAL**	**BILLED**		**CUMULATIVE BILLED TOTALS**					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	0	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	420	20,140	20,140	$ 3,976	420	3.13%	20,140	0.12%	$ 3,976	0.72%
3	3	100	*101-200*	346	52,764	52,764	$ 4,570	766	5.72%	72,904	0.45%	$ 8,546	1.54%
4	4	100	*201-300*	403	102,549	102,549	$ 6,795	1,169	8.72%	175,453	1.09%	$ 15,341	2.77%
5	5	100	*301-400*	599	210,995	210,995	$ 12,196	1,768	13.19%	386,448	2.40%	$ 27,537	4.97%
6	6	100	*401-500*	737	332,733	332,733	$ 17,624	2,505	18.69%	719,181	4.46%	$ 45,160	8.16%
7	7	100	*501-600*	799	441,410	441,410	$ 21,458	3,304	24.65%	1,160,591	7.20%	$ 66,619	12.03%
8	8	100	*601-700*	837	544,651	544,651	$ 24,371	4,141	30.90%	1,705,242	10.57%	$ 90,989	16.43%
9	9	100	*701-800*	797	599,787	599,787	$ 25,073	4,938	36.84%	2,305,029	14.29%	$ 116,062	20.96%
10	10	100	*801-900*	823	700,132	700,132	$ 27,748	5,761	42.98%	3,005,161	18.64%	$ 143,810	25.97%
11	11	100	*901-1000*	718	681,960	681,960	$ 25,845	6,479	48.34%	3,687,121	22.87%	$ 169,655	30.64%
12	12	100	*1001-1100*	733	768,818	768,818	$ 28,055	7,212	53.81%	4,455,939	27.63%	$ 197,710	35.71%
13	13	100	*1101-1200*	651	748,262	748,262	$ 26,422	7,863	58.67%	5,204,201	32.27%	$ 224,132	40.48%
14	14	100	*1201-1300*	629	785,844	785,844	$ 26,975	8,492	63.36%	5,990,045	37.15%	$ 251,106	45.35%
15	15	100	*1301-1400*	596	804,830	804,830	$ 26,944	9,088	67.81%	6,794,875	42.14%	$ 278,051	50.22%
16	16	100	1401-1500	563	815,575	815,575	$ 26,725	9,651	72.01%	7,610,450	47.20%	$ 304,776	55.04%
17	17	500	1501-2000	1,870	3,233,678	3,233,678	$ 100,835	11,521	85.96%	10,844,128	67.25%	$ 405,611	73.25%
18	18	500	2001-2500	945	2,107,202	2,107,202	$ 61,837	12,466	93.01%	12,951,330	80.32%	$ 467,448	84.42%
19	19	500	2501-3000	496	1,351,249	1,351,249	$ 38,097	12,962	96.71%	14,302,579	88.70%	$ 505,545	91.30%
20	20		over 3000	441	1,822,842	1,822,842	$ 48,166	13,403	100.00%	16,125,421	100.00%	$ 553,711	100.00%
21	**TOTAL**			13,403	16,125,421	16,125,421	$ 553,711						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Electric Heating Appliance Service - R-3

Description: April 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED			CUMULATIVE BILLED TOTALS							
				Number	Metered	Billed	Revenue		Bills		Usage		Revenue			
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block		Number	% of Total	Usage	% of Total	Amount		% of Total
1	1	-	0	0	0	0		0	0	0.00%	0	0.00%		0	0.00%
2	2	100	*1-100*	436	21,543	21,543	$	4,150	436	3.28%	21,543	0.16%	$	4,150	0.85%
3	3	100	*101-200*	379	56,658	56,658	$	4,966	815	6.13%	78,201	0.58%	$	9,116	1.86%
4	4	100	*201-300*	473	120,389	120,389	$	7,976	1,288	9.69%	198,590	1.48%	$	17,092	3.49%
5	5	100	*301-400*	709	250,389	250,389	$	14,459	1,997	15.03%	448,979	3.34%	$	31,550	6.44%
6	6	100	*401-500*	865	390,784	390,784	$	20,694	2,862	21.54%	839,763	6.24%	$	52,244	10.67%
7	7	100	*501-600*	940	517,234	517,234	$	25,197	3,802	28.61%	1,356,997	10.09%	$	77,441	15.81%
8	8	100	*601-700*	954	620,230	620,230	$	27,764	4,756	35.79%	1,977,227	14.70%	$	105,206	21.48%
9	9	100	*701-800*	935	702,564	702,564	$	29,389	5,691	42.83%	2,679,791	19.92%	$	134,595	27.48%
10	10	100	*801-900*	917	779,787	779,787	$	30,911	6,608	49.73%	3,459,578	25.72%	$	165,506	33.79%
11	11	100	*901-1000*	910	864,010	864,010	$	32,749	7,518	56.58%	4,323,588	32.14%	$	198,254	40.47%
12	12	100	*1001-1100*	845	886,210	886,210	$	32,340	8,363	62.94%	5,209,798	38.73%	$	230,594	47.07%
13	13	100	*1101-1200*	769	885,229	885,229	$	31,242	9,132	68.73%	6,095,027	45.31%	$	261,836	53.45%
14	14	100	*1201-1300*	712	888,624	888,624	$	30,513	9,844	74.09%	6,983,651	51.91%	$	292,349	59.68%
15	15	100	*1301-1400*	570	767,561	767,561	$	25,719	10,414	78.38%	7,751,212	57.62%	$	318,068	64.93%
16	16	100	1401-1500	496	718,292	718,292	$	23,539	10,910	82.11%	8,469,504	62.96%	$	341,607	69.74%
17	17	500	1501-2000	1,451	2,482,945	2,482,945	$	77,639	12,361	93.03%	10,952,449	81.41%	$	419,247	85.59%
18	18	500	2001-2500	545	1,206,134	1,206,134	$	35,453	12,906	97.13%	12,158,583	90.38%	$	454,699	92.82%
19	19	500	2501-3000	209	571,007	571,007	$	16,091	13,115	98.71%	12,729,590	94.62%	$	470,790	96.11%
20	20		over 3000	172	723,224	723,224	$	19,068	13,287	100.00%	13,452,814	100.00%	$	489,858	100.00%
21	**TOTAL**			13,287	13,452,814	13,452,814	$	489,858							

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Electric Heating Appliance Service - R-3

Description: May 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	0	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	477	23,870	23,870	$ 4,752	477	3.63%	23,870	0.20%	$ 4,752	0.75%
3	3	100	*101-200*	434	65,250	65,250	$ 6,248	911	6.93%	89,120	0.75%	$ 10,999	1.73%
4	4	100	*201-300*	621	157,913	157,913	$ 11,793	1,532	11.65%	247,033	2.08%	$ 22,792	3.58%
5	5	100	*301-400*	886	312,755	312,755	$ 20,690	2,418	18.39%	559,788	4.71%	$ 43,482	6.84%
6	6	100	*401-500*	970	437,922	437,922	$ 26,874	3,388	25.77%	997,710	8.39%	$ 70,356	11.06%
7	7	100	*501-600*	1,047	577,756	577,756	$ 33,651	4,435	33.73%	1,575,466	13.26%	$ 104,007	16.36%
8	8	100	*601-700*	1,058	689,050	689,050	$ 38,656	5,493	41.78%	2,264,516	19.05%	$ 142,662	22.43%
9	9	100	*701-800*	995	747,472	747,472	$ 40,750	6,488	49.35%	3,011,988	25.34%	$ 183,412	28.84%
10	10	100	*801-900*	1,021	869,736	869,736	$ 46,355	7,509	57.11%	3,881,724	32.66%	$ 229,767	36.13%
11	11	100	*901-1000*	957	908,509	908,509	$ 47,573	8,466	64.39%	4,790,233	40.30%	$ 277,340	43.61%
12	12	100	*1001-1100*	818	857,692	857,692	$ 44,249	9,284	70.61%	5,647,925	47.52%	$ 321,589	50.57%
13	13	100	*1101-1200*	753	865,572	865,572	$ 44,094	10,037	76.34%	6,513,497	54.80%	$ 365,683	57.50%
14	14	100	*1201-1300*	591	738,164	738,164	$ 37,207	10,628	80.83%	7,251,661	61.02%	$ 402,890	63.35%
15	15	100	*1301-1400*	478	644,654	644,654	$ 32,198	11,106	84.47%	7,896,315	66.44%	$ 435,089	68.42%
16	16	100	1401-1500	415	601,437	601,437	$ 29,800	11,521	87.63%	8,497,752	71.50%	$ 464,888	73.10%
17	17	500	1501-2000	1,067	1,822,024	1,822,024	$ 90,841	12,588	95.74%	10,319,776	86.83%	$ 555,729	87.39%
18	18	500	2001-2500	330	727,034	727,034	$ 36,827	12,918	98.25%	11,046,810	92.95%	$ 592,556	93.18%
19	19	500	2501-3000	111	302,900	302,900	$ 15,503	13,029	99.09%	11,349,710	95.50%	$ 608,060	95.62%
20	20		over 3000	119	535,328	535,328	$ 27,867	13,148	100.00%	11,885,038	100.00%	$ 635,926	100.00%
21	**TOTAL**			13,148	11,885,038	11,885,038	$ 635,926						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Electric Heating Appliance Service - R-3

Description: June 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
								Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	Number of Bills By Block	Metered Usage By Block	Billed Usage By Block	Revenue By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	0	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	415	20,718	20,718	$ 4,132	415	3.18%	20,718	0.13%	$ 4,132	0.49%
3	3	100	*101-200*	363	54,965	54,965	$ 5,243	778	5.97%	75,683	0.47%	$ 9,375	1.11%
4	4	100	*201-300*	442	111,435	111,435	$ 8,351	1,220	9.36%	187,118	1.16%	$ 17,726	2.11%
5	5	100	*301-400*	518	182,287	182,287	$ 12,072	1,738	13.33%	369,405	2.29%	$ 29,797	3.54%
6	6	100	*401-500*	629	282,983	282,983	$ 17,383	2,367	18.15%	652,388	4.04%	$ 47,180	5.61%
7	7	100	*501-600*	681	375,037	375,037	$ 21,854	3,048	23.37%	1,027,425	6.36%	$ 69,034	8.20%
8	8	100	*601-700*	670	436,244	436,244	$ 24,474	3,718	28.51%	1,463,669	9.06%	$ 93,509	11.11%
9	9	100	*701-800*	697	523,072	523,072	$ 28,522	4,415	33.85%	1,986,741	12.30%	$ 122,030	14.50%
10	10	100	*801-900*	664	565,186	565,186	$ 30,127	5,079	38.95%	2,551,927	15.80%	$ 152,157	18.08%
11	11	100	*901-1000*	731	694,547	694,547	$ 36,364	5,810	44.55%	3,246,474	20.10%	$ 188,522	22.40%
12	12	100	*1001-1100*	694	729,080	729,080	$ 37,604	6,504	49.87%	3,975,554	24.61%	$ 226,126	26.87%
13	13	100	*1101-1200*	645	740,624	740,624	$ 37,734	7,149	54.82%	4,716,178	29.20%	$ 263,860	31.35%
14	14	100	*1201-1300*	687	858,481	858,481	$ 43,269	7,836	60.09%	5,574,659	34.52%	$ 307,129	36.49%
15	15	100	*1301-1400*	663	895,994	895,994	$ 44,741	8,499	65.17%	6,470,653	40.06%	$ 351,870	41.81%
16	16	100	1401-1500	588	852,416	852,416	$ 42,234	9,087	69.68%	7,323,069	45.34%	$ 394,104	46.83%
17	17	500	1501-2000	2,049	3,528,472	3,528,472	$ 176,024	11,136	85.39%	10,851,541	67.19%	$ 570,128	67.74%
18	18	500	2001-2500	997	2,215,157	2,215,157	$ 112,258	12,133	93.04%	13,066,698	80.90%	$ 682,385	81.08%
19	19	500	2501-3000	460	1,249,925	1,249,925	$ 63,963	12,593	96.56%	14,316,623	88.64%	$ 746,348	88.68%
20	20		over 3000	448	1,834,644	1,834,644	$ 95,260	13,041	100.00%	16,151,267	100.00%	$ 841,608	100.00%
21	**TOTAL**			13,041	16,151,267	16,151,267	$ 841,608						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Electric Heating Appliance Service - R-3

Description: July 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	0	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	379	18,215	18,215	$ 3,742	379	2.93%	18,215	0.10%	$ 3,742	0.40%
3	3	100	*101-200*	320	46,927	46,927	$ 4,554	699	5.41%	65,142	0.36%	$ 8,297	0.89%
4	4	100	*201-300*	338	85,754	85,754	$ 6,410	1,037	8.03%	150,896	0.83%	$ 14,706	1.57%
5	5	100	*301-400*	356	126,255	126,255	$ 8,339	1,393	10.78%	277,151	1.53%	$ 23,046	2.46%
6	6	100	*401-500*	472	213,187	213,187	$ 13,081	1,865	14.43%	490,338	2.71%	$ 36,127	3.86%
7	7	100	*501-600*	546	301,543	301,543	$ 17,560	2,411	18.66%	791,881	4.38%	$ 53,686	5.74%
8	8	100	*601-700*	593	385,561	385,561	$ 21,638	3,004	23.25%	1,177,442	6.51%	$ 75,324	8.05%
9	9	100	*701-800*	568	427,750	427,750	$ 23,309	3,572	27.65%	1,605,192	8.88%	$ 98,632	10.54%
10	10	100	*801-900*	628	534,632	534,632	$ 28,498	4,200	32.51%	2,139,824	11.83%	$ 127,130	13.58%
11	11	100	*901-1000*	596	565,958	565,958	$ 29,634	4,796	37.12%	2,705,782	14.96%	$ 156,765	16.75%
12	12	100	*1001-1100*	605	636,404	636,404	$ 32,818	5,401	41.80%	3,342,186	18.48%	$ 189,582	20.26%
13	13	100	*1101-1200*	668	768,687	768,687	$ 39,153	6,069	46.97%	4,110,873	22.73%	$ 228,735	24.44%
14	14	100	*1201-1300*	630	786,066	786,066	$ 39,627	6,699	51.85%	4,896,939	27.08%	$ 268,362	28.67%
15	15	100	*1301-1400*	636	858,455	858,455	$ 42,873	7,335	56.77%	5,755,394	31.83%	$ 311,235	33.25%
16	16	100	1401-1500	630	914,145	914,145	$ 45,288	7,965	61.65%	6,669,539	36.88%	$ 356,522	38.09%
17	17	500	1501-2000	2,332	4,042,341	4,042,341	$ 201,752	10,297	79.70%	10,711,880	59.24%	$ 558,275	59.65%
18	18	500	2001-2500	1,270	2,827,296	2,827,296	$ 143,294	11,567	89.53%	13,539,176	74.88%	$ 701,569	74.96%
19	19	500	2501-3000	689	1,878,155	1,878,155	$ 96,125	12,256	94.86%	15,417,331	85.26%	$ 797,694	85.23%
20	20		over 3000	664	2,664,814	2,664,814	$ 138,284	12,920	100.00%	18,082,145	100.00%	$ 935,978	100.00%
21	**TOTAL**			12,920	18,082,145	18,082,145	$ 935,978						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Electric Heating Appliance Service - R-3

Description: August 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	0	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	403	19,760	19,760	$ 3,997	403	3.15%	19,760	0.12%	$ 3,997	0.45%
3	3	100	*101-200*	304	44,727	44,727	$ 4,333	707	5.52%	64,487	0.38%	$ 8,330	0.94%
4	4	100	*201-300*	316	79,767	79,767	$ 5,975	1,023	7.99%	144,254	0.85%	$ 14,304	1.62%
5	5	100	*301-400*	491	171,981	171,981	$ 11,407	1,514	11.82%	316,235	1.86%	$ 25,711	2.91%
6	6	100	*401-500*	548	247,569	247,569	$ 15,190	2,062	16.10%	563,804	3.31%	$ 40,901	4.63%
7	7	100	*501-600*	588	324,446	324,446	$ 18,898	2,650	20.70%	888,250	5.22%	$ 59,798	6.77%
8	8	100	*601-700*	602	391,764	391,764	$ 21,981	3,252	25.40%	1,280,014	7.52%	$ 81,780	9.25%
9	9	100	*701-800*	605	454,057	454,057	$ 24,758	3,857	30.12%	1,734,071	10.18%	$ 106,538	12.05%
10	10	100	*801-900*	677	576,320	576,320	$ 30,720	4,534	35.41%	2,310,391	13.57%	$ 137,258	15.53%
11	11	100	*901-1000*	630	599,283	599,283	$ 31,371	5,164	40.33%	2,909,674	17.08%	$ 168,629	19.08%
12	12	100	*1001-1100*	661	693,714	693,714	$ 35,785	5,825	45.49%	3,603,388	21.16%	$ 204,413	23.13%
13	13	100	*1101-1200*	663	761,086	761,086	$ 38,778	6,488	50.67%	4,364,474	25.63%	$ 243,192	27.51%
14	14	100	*1201-1300*	634	791,949	791,949	$ 39,918	7,122	55.62%	5,156,423	30.28%	$ 283,109	32.03%
15	15	100	*1301-1400*	594	802,300	802,300	$ 40,065	7,716	60.26%	5,958,723	34.99%	$ 323,175	36.56%
16	16	100	1401-1500	590	855,449	855,449	$ 42,383	8,306	64.87%	6,814,172	40.01%	$ 365,558	41.36%
17	17	500	1501-2000	2,226	3,843,761	3,843,761	$ 191,790	10,532	82.25%	10,657,933	62.58%	$ 557,347	63.06%
18	18	500	2001-2500	1,097	2,432,417	2,432,417	$ 123,254	11,629	90.82%	13,090,350	76.86%	$ 680,602	77.00%
19	19	500	2501-3000	596	1,621,310	1,621,310	$ 82,972	12,225	95.47%	14,711,660	86.38%	$ 763,574	86.39%
20	20		over 3000	580	2,319,111	2,319,111	$ 120,332	12,805	100.00%	17,030,771	100.00%	$ 883,905	100.00%
21	**TOTAL**			12,805	17,030,771	17,030,771	$ 883,905						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Electric Heating Appliance Service - R-3

Description: September 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	0	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	373	17,461	17,461	$ 3,663	373	2.94%	17,461	0.11%	$ 3,663	0.44%
3	3	100	*101-200*	291	43,067	43,067	$ 4,159	664	5.24%	60,528	0.37%	$ 7,821	0.93%
4	4	100	*201-300*	366	92,845	92,845	$ 6,940	1,030	8.13%	153,373	0.95%	$ 14,762	1.76%
5	5	100	*301-400*	488	172,694	172,694	$ 11,415	1,518	11.98%	326,067	2.02%	$ 26,177	3.11%
6	6	100	*401-500*	609	274,356	274,356	$ 16,846	2,127	16.79%	600,423	3.71%	$ 43,023	5.11%
7	7	100	*501-600*	628	346,516	346,516	$ 20,183	2,755	21.74%	946,939	5.85%	$ 63,206	7.51%
8	8	100	*601-700*	604	393,342	393,342	$ 22,067	3,359	26.51%	1,340,281	8.28%	$ 85,273	10.14%
9	9	100	*701-800*	646	484,824	484,824	$ 26,436	4,005	31.61%	1,825,105	11.28%	$ 111,708	13.28%
10	10	100	*801-900*	690	587,006	587,006	$ 31,293	4,695	37.05%	2,412,111	14.91%	$ 143,002	17.00%
11	11	100	*901-1000*	678	644,269	644,269	$ 33,731	5,373	42.40%	3,056,380	18.89%	$ 176,733	21.01%
12	12	100	*1001-1100*	682	714,815	714,815	$ 36,880	6,055	47.79%	3,771,195	23.31%	$ 213,613	25.40%
13	13	100	*1101-1200*	706	811,953	811,953	$ 41,360	6,761	53.36%	4,583,148	28.33%	$ 254,973	30.31%
14	14	100	*1201-1300*	657	821,375	821,375	$ 41,397	7,418	58.54%	5,404,523	33.40%	$ 296,369	35.24%
15	15	100	*1301-1400*	634	855,213	855,213	$ 42,714	8,052	63.55%	6,259,736	38.69%	$ 339,083	40.31%
16	16	100	1401-1500	557	807,381	807,381	$ 40,003	8,609	67.94%	7,067,117	43.68%	$ 379,086	45.07%
17	17	500	1501-2000	2,075	3,582,327	3,582,327	$ 178,743	10,684	84.32%	10,649,444	65.82%	$ 557,829	66.32%
18	18	500	2001-2500	1,051	2,339,926	2,339,926	$ 118,594	11,735	92.61%	12,989,370	80.28%	$ 676,422	80.42%
19	19	500	2501-3000	453	1,230,759	1,230,759	$ 62,982	12,188	96.19%	14,220,129	87.89%	$ 739,404	87.91%
20	20		over 3000	483	1,959,399	1,959,399	$ 101,710	12,671	100.00%	16,179,528	100.00%	$ 841,114	100.00%
21	**TOTAL**			12,671	16,179,528	16,179,528	$ 841,114						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Electric Heating Appliance Service - R-3

Description: October 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	0	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	393	20,213	20,213	$ 3,769	393	3.12%	20,213	0.16%	$ 3,769	0.80%
3	3	100	*101-200*	366	55,066	55,066	$ 4,808	759	6.03%	75,279	0.58%	$ 8,577	1.82%
4	4	100	*201-300*	529	134,297	134,297	$ 8,908	1,288	10.23%	209,576	1.61%	$ 17,485	3.71%
5	5	100	*301-400*	675	238,821	238,821	$ 13,781	1,963	15.58%	448,397	3.44%	$ 31,266	6.64%
6	6	100	*401-500*	816	367,857	367,857	$ 19,493	2,779	22.06%	816,254	6.26%	$ 50,759	10.78%
7	7	100	*501-600*	808	444,242	444,242	$ 21,651	3,587	28.48%	1,260,496	9.67%	$ 72,410	15.38%
8	8	100	*601-700*	850	553,099	553,099	$ 24,749	4,437	35.23%	1,813,595	13.91%	$ 97,159	20.64%
9	9	100	*701-800*	867	651,346	651,346	$ 27,249	5,304	42.11%	2,464,941	18.91%	$ 124,408	26.43%
10	10	100	*801-900*	853	726,456	726,456	$ 28,778	6,157	48.88%	3,191,397	24.48%	$ 153,186	32.54%
11	11	100	*901-1000*	819	778,670	778,670	$ 29,498	6,976	55.38%	3,970,067	30.45%	$ 182,684	38.81%
12	12	100	*1001-1100*	829	871,063	871,063	$ 31,765	7,805	61.96%	4,841,130	37.13%	$ 214,449	45.55%
13	13	100	*1101-1200*	725	833,313	833,313	$ 29,425	8,530	67.72%	5,674,443	43.52%	$ 243,874	51.80%
14	14	100	*1201-1300*	640	798,812	798,812	$ 27,429	9,170	72.80%	6,473,255	49.65%	$ 271,303	57.63%
15	15	100	*1301-1400*	556	748,953	748,953	$ 25,093	9,726	77.21%	7,222,208	55.40%	$ 296,396	62.96%
16	16	100	1401-1500	481	697,588	697,588	$ 22,851	10,207	81.03%	7,919,796	60.75%	$ 319,247	67.82%
17	17	500	1501-2000	1,415	2,428,719	2,428,719	$ 75,883	11,622	92.27%	10,348,515	79.38%	$ 395,130	83.93%
18	18	500	2001-2500	577	1,282,102	1,282,102	$ 37,653	12,199	96.85%	11,630,617	89.21%	$ 432,783	91.93%
19	19	500	2501-3000	203	548,778	548,778	$ 15,494	12,402	98.46%	12,179,395	93.42%	$ 448,277	95.22%
20	20		over 3000	194	858,097	858,097	$ 22,481	12,596	100.00%	13,037,492	100.00%	$ 470,758	100.00%
21	**TOTAL**			12,596	13,037,492	13,037,492	$ 470,758						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Electric Heating Appliance Service - R-3

Description: November 2018

USAGE UNIT			Specify Units		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	0	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	418	20,884	20,884	$ 3,987	418	3.35%	20,884	0.17%	$ 3,987	0.89%
3	3	100	*101-200*	384	57,688	57,688	$ 5,041	802	6.42%	78,572	0.64%	$ 9,028	2.01%
4	4	100	*201-300*	525	133,310	133,310	$ 8,841	1,327	10.62%	211,882	1.74%	$ 17,870	3.98%
5	5	100	*301-400*	720	253,436	253,436	$ 14,653	2,047	16.39%	465,318	3.82%	$ 32,523	7.24%
6	6	100	*401-500*	856	386,916	386,916	$ 20,486	2,903	23.24%	852,234	6.99%	$ 53,008	11.79%
7	7	100	*501-600*	958	528,044	528,044	$ 25,701	3,861	30.91%	1,380,278	11.32%	$ 78,709	17.51%
8	8	100	*601-700*	979	636,085	636,085	$ 28,483	4,840	38.75%	2,016,363	16.54%	$ 107,192	23.85%
9	9	100	*701-800*	918	688,161	688,161	$ 28,817	5,758	46.10%	2,704,524	22.19%	$ 136,009	30.26%
10	10	100	*801-900*	898	762,851	762,851	$ 30,252	6,656	53.29%	3,467,375	28.45%	$ 166,261	36.99%
11	11	100	*901-1000*	880	834,891	834,891	$ 31,654	7,536	60.33%	4,302,266	35.30%	$ 197,916	44.04%
12	12	100	*1001-1100*	812	853,590	853,590	$ 31,122	8,348	66.83%	5,155,856	42.30%	$ 229,038	50.96%
13	13	100	*1101-1200*	694	796,882	796,882	$ 28,148	9,042	72.39%	5,952,738	48.84%	$ 257,187	57.23%
14	14	100	*1201-1300*	568	709,501	709,501	$ 24,356	9,610	76.94%	6,662,239	54.66%	$ 281,542	62.64%
15	15	100	*1301-1400*	484	653,275	653,275	$ 21,874	10,094	80.81%	7,315,514	60.02%	$ 303,416	67.51%
16	16	100	1401-1500	407	589,682	589,682	$ 19,322	10,501	84.07%	7,905,196	64.85%	$ 322,738	71.81%
17	17	500	1501-2000	1,120	1,916,600	1,916,600	$ 59,930	11,621	93.03%	9,821,796	80.58%	$ 382,668	85.15%
18	18	500	2001-2500	496	1,099,378	1,099,378	$ 32,304	12,117	97.01%	10,921,174	89.60%	$ 414,972	92.33%
19	19	500	2501-3000	199	539,706	539,706	$ 15,229	12,316	98.60%	11,460,880	94.02%	$ 430,201	95.72%
20	20		over 3000	175	728,401	728,401	$ 19,229	12,491	100.00%	12,189,281	100.00%	$ 449,431	100.00%
21	**TOTAL**			12,491	12,189,281	12,189,281	$ 449,431						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Electric Heating Appliance Service - R-3

Description: December 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
								Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	Number of Bills By Block	Metered Usage By Block	Billed Usage By Block	Revenue By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	0	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	337	16,149	16,149	$ 3,190	337	2.72%	16,149	0.09%	$ 3,190	0.53%
3	3	100	*101-200*	280	41,081	41,081	$ 3,641	617	4.98%	57,230	0.30%	$ 6,831	1.13%
4	4	100	*201-300*	253	63,893	63,893	$ 4,248	870	7.02%	121,123	0.64%	$ 11,079	1.84%
5	5	100	*301-400*	374	132,075	132,075	$ 7,627	1,244	10.03%	253,198	1.35%	$ 18,705	3.10%
6	6	100	*401-500*	479	217,153	217,153	$ 11,486	1,723	13.90%	470,351	2.50%	$ 30,192	5.01%
7	7	100	*501-600*	537	295,972	295,972	$ 14,406	2,260	18.23%	766,323	4.08%	$ 44,598	7.40%
8	8	100	*601-700*	594	387,236	387,236	$ 17,312	2,854	23.02%	1,153,559	6.14%	$ 61,909	10.28%
9	9	100	*701-800*	566	425,460	425,460	$ 17,794	3,420	27.59%	1,579,019	8.41%	$ 79,704	13.23%
10	10	100	*801-900*	571	486,146	486,146	$ 19,261	3,991	32.19%	2,065,165	10.99%	$ 98,965	16.43%
11	11	100	*901-1000*	547	519,087	519,087	$ 19,679	4,538	36.61%	2,584,252	13.76%	$ 118,644	19.69%
12	12	100	*1001-1100*	527	555,198	555,198	$ 20,227	5,065	40.86%	3,139,450	16.71%	$ 138,870	23.05%
13	13	100	*1101-1200*	560	643,878	643,878	$ 22,733	5,625	45.37%	3,783,328	20.14%	$ 161,604	26.82%
14	14	100	*1201-1300*	554	691,431	691,431	$ 23,742	6,179	49.84%	4,474,759	23.82%	$ 185,346	30.77%
15	15	100	*1301-1400*	510	687,547	687,547	$ 23,030	6,689	53.96%	5,162,306	27.48%	$ 208,376	34.59%
16	16	100	1401-1500	490	710,493	710,493	$ 23,275	7,179	57.91%	5,872,799	31.26%	$ 231,651	38.45%
17	17	500	1501-2000	2,015	3,493,021	3,493,021	$ 108,852	9,194	74.16%	9,365,820	49.86%	$ 340,502	56.52%
18	18	500	2001-2500	1,322	2,958,054	2,958,054	$ 86,742	10,516	84.83%	12,323,874	65.61%	$ 427,244	70.92%
19	19	500	2501-3000	862	2,351,630	2,351,630	$ 66,285	11,378	91.78%	14,675,504	78.13%	$ 493,529	81.92%
20	20		over 3000	1,019	4,109,018	4,109,018	$ 108,926	12,397	100.00%	18,784,522	100.00%	$ 602,455	100.00%
21	**TOTAL**			12,397	18,784,522	18,784,522	$ 602,455						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential NM Service

Description: January 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED			CUMULATIVE BILLED TOTALS						
				Number	Metered	Billed	Revenue		Bills		Usage		Revenue		
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block		Number	% of Total	Usage	% of Total		Amount	% of Total
1	1	-	0	9	0	0		0	0	0.00%	0	0.00%		0	0.00%
2	2	100	*1-100*	1	66	66	$	10	1	1.75%	66	0.12%	$	10	0.43%
3	3	100	*101-200*	2	321	321	$	27	3	5.26%	387	0.70%	$	37	1.59%
4	4	100	*201-300*	3	776	776	$	51	6	10.53%	1,163	2.12%	$	88	3.77%
5	5	100	*301-400*	4	1,482	1,482	$	84	10	17.54%	2,645	4.82%	$	172	7.37%
6	6	100	*401-500*	4	1,813	1,813	$	96	14	24.56%	4,458	8.12%	$	268	11.47%
7	7	100	*501-600*	3	1,691	1,691	$	84	17	29.82%	6,149	11.20%	$	352	15.05%
8	8	100	*601-700*	5	3,345	3,345	$	159	22	38.60%	9,494	17.29%	$	510	21.83%
9	9	100	*701-800*	1	761	761	$	35	23	40.35%	10,255	18.68%	$	545	23.33%
10	10	100	*801-900*	4	3,373	3,373	$	152	27	47.37%	13,628	24.82%	$	697	29.82%
11	11	100	*901-1000*	1	999	999	$	44	28	49.12%	14,627	26.64%	$	741	31.68%
12	12	100	*1001-1100*	3	3,126	3,126	$	135	31	54.39%	17,753	32.33%	$	876	37.46%
13	13	100	*1101-1200*	1	1,101	1,101	$	47	32	56.14%	18,854	34.34%	$	923	39.48%
14	14	100	*1201-1300*	2	2,536	2,536	$	106	34	59.65%	21,390	38.96%	$	1,029	44.03%
15	15	100	*1301-1400*	2	2,625	2,625	$	109	36	63.16%	24,015	43.74%	$	1,139	48.71%
16	16	100	1401-1500	1	1,441	1,441	$	59	37	64.91%	25,456	46.36%	$	1,198	51.25%
17	17	500	1501-2000	4	6,755	6,755	$	273	41	71.93%	32,211	58.66%	$	1,471	62.92%
18	18	500	2001-2500	2	4,568	4,568	$	179	43	75.44%	36,779	66.98%	$	1,650	70.58%
19	19	500	2501-3000	3	8,353	8,353	$	322	46	80.70%	45,132	82.20%	$	1,972	84.37%
20	20		over 3000	2	9,775	9,775	$	365	48	84.21%	54,907	100.00%	$	2,338	100.00%
21	**TOTAL**			57	54,907	54,907	$	2,338							

Supporting Schedules
As needed

Southwestern Electric Power Company
Docket No. 19-008-U
Test Year Ending December 31, 2018

Schedule H-4
Title: Bill Frequency Analysis
Residential NM Service

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential NM Service

Description: February 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	11	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	5	294	294	$ 49	5	8.06%	294	0.62%	$ 49	2.36%
3	3	100	*101-200*	4	631	631	$ 54	9	14.52%	925	1.96%	$ 103	4.93%
4	4	100	*201-300*	6	1,577	1,577	$ 103	15	24.19%	2,502	5.29%	$ 206	9.86%
5	5	100	*301-400*	4	1,429	1,429	$ 82	19	30.65%	3,931	8.31%	$ 288	13.79%
6	6	100	*401-500*	7	3,287	3,287	$ 172	26	41.94%	7,218	15.26%	$ 460	22.02%
7	7	100	*501-600*	2	1,104	1,104	$ 55	28	45.16%	8,322	17.60%	$ 515	24.66%
8	8	100	*601-700*	1	661	661	$ 31	29	46.77%	8,983	19.00%	$ 546	26.16%
9	9	100	*701-800*	2	1,460	1,460	$ 68	31	50.00%	10,443	22.08%	$ 614	29.41%
10	10	100	*801-900*	2	1,763	1,763	$ 79	33	53.23%	12,206	25.81%	$ 693	33.17%
11	11	100	*901-1000*	3	2,746	2,746	$ 122	36	58.06%	14,952	31.62%	$ 814	38.99%
12	12	100	*1001-1100*	1	1,089	1,089	$ 47	37	59.68%	16,041	33.92%	$ 861	41.23%
13	13	100	*1101-1200*	1	1,182	1,182	$ 50	38	61.29%	17,223	36.42%	$ 911	43.63%
14	14	100	*1201-1300*	2	2,569	2,569	$ 107	40	64.52%	19,792	41.85%	$ 1,019	48.78%
15	15	100	*1301-1400*	1	1,320	1,320	$ 55	41	66.13%	21,112	44.64%	$ 1,074	51.41%
16	16	100	1401-1500	1	1,458	1,458	$ 60	42	67.74%	22,570	47.73%	$ 1,134	54.28%
17	17	500	1501-2000	3	4,977	4,977	$ 201	45	72.58%	27,547	58.25%	$ 1,335	63.93%
18	18	500	2001-2500	3	6,734	6,734	$ 264	48	77.42%	34,281	72.49%	$ 1,599	76.59%
19	19	500	2501-3000	1	2,950	2,950	$ 113	49	79.03%	37,231	78.73%	$ 1,713	82.01%
20	20		over 3000	2	10,058	10,058	$ 376	51	82.26%	47,289	100.00%	$ 2,088	100.00%
21	**TOTAL**			62	47,289	47,289	$ 2,088						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential NM Service

Description: March 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
								Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	Number of Bills By Block	Metered Usage By Block	Billed Usage By Block	Revenue By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	14	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	2	137	137	$ 20	2	3.45%	137	0.37%	$ 20	1.22%
3	3	100	*101-200*	3	374	374	$ 37	5	8.62%	511	1.37%	$ 57	3.41%
4	4	100	*201-300*	7	1,684	1,684	$ 115	12	20.69%	2,195	5.90%	$ 172	10.26%
5	5	100	*301-400*	6	2,172	2,172	$ 124	18	31.03%	4,367	11.74%	$ 296	17.68%
6	6	100	*401-500*	3	1,237	1,237	$ 68	21	36.21%	5,604	15.06%	$ 363	21.72%
7	7	100	*501-600*	5	2,789	2,789	$ 139	26	44.83%	8,393	22.56%	$ 502	30.00%
8	8	100	*601-700*	2	1,257	1,257	$ 61	28	48.28%	9,650	25.93%	$ 562	33.62%
9	9	100	*701-800*	1	745	745	$ 34	29	50.00%	10,395	27.94%	$ 597	35.68%
10	10	100	*801-900*	4	3,331	3,331	$ 150	33	56.90%	13,726	36.89%	$ 747	44.66%
11	11	100	*901-1000*	0	0	0	$ -	33	56.90%	13,726	36.89%	$ 747	44.66%
12	12	100	*1001-1100*	2	2,082	2,082	$ 90	35	60.34%	15,808	42.48%	$ 837	50.04%
13	13	100	*1101-1200*	1	1,128	1,128	$ 48	36	62.07%	16,936	45.52%	$ 885	52.91%
14	14	100	*1201-1300*	2	2,550	2,550	$ 107	38	65.52%	19,486	52.37%	$ 992	59.30%
15	15	100	*1301-1400*	1	1,365	1,365	$ 57	39	67.24%	20,851	56.04%	$ 1,049	62.68%
16	16	100	1401-1500	0	0	0	$ -	39	67.24%	20,851	56.04%	$ 1,049	62.68%
17	17	500	1501-2000	2	3,701	3,701	$ 148	41	70.69%	24,552	65.98%	$ 1,197	71.53%
18	18	500	2001-2500	0	0	0	$ -	41	70.69%	24,552	65.98%	$ 1,197	71.53%
19	19	500	2501-3000	1	2,735	2,735	$ 106	42	72.41%	27,287	73.33%	$ 1,302	77.84%
20	20		over 3000	2	9,922	9,922	$ 371	44	75.86%	37,209	100.00%	$ 1,673	100.00%
21	**TOTAL**			58	37,209	37,209	$ 1,673						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential NM Service

Description: April 2018

USAGE UNIT			*Specify Units*		**ACTUAL**	**BILLED**		**CUMULATIVE BILLED TOTALS**					
								Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	Number of Bills By Block	Metered Usage By Block	Billed Usage By Block	Revenue By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	20	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	5	319	319	$ 50	5	8.47%	319	1.09%	$ 50	3.71%
3	3	100	*101-200*	4	597	597	$ 52	9	15.25%	916	3.13%	$ 103	7.59%
4	4	100	*201-300*	3	711	711	$ 49	12	20.34%	1,627	5.55%	$ 151	11.19%
5	5	100	*301-400*	7	2,358	2,358	$ 139	19	32.20%	3,985	13.60%	$ 290	21.45%
6	6	100	*401-500*	3	1,424	1,424	$ 74	22	37.29%	5,409	18.46%	$ 364	26.95%
7	7	100	*501-600*	5	2,798	2,798	$ 139	27	45.76%	8,207	28.01%	$ 503	37.23%
8	8	100	*601-700*	0	0	0	$ -	27	45.76%	8,207	28.01%	$ 503	37.23%
9	9	100	*701-800*	3	2,298	2,298	$ 106	30	50.85%	10,505	35.85%	$ 609	45.04%
10	10	100	*801-900*	1	806	806	$ 37	31	52.54%	11,311	38.60%	$ 645	47.75%
11	11	100	*901-1000*	1	925	925	$ 41	32	54.24%	12,236	41.76%	$ 686	50.77%
12	12	100	*1001-1100*	1	1,060	1,060	$ 46	33	55.93%	13,296	45.38%	$ 732	54.15%
13	13	100	*1101-1200*	2	2,264	2,264	$ 97	35	59.32%	15,560	53.10%	$ 828	61.30%
14	14	100	*1201-1300*	0	0	0	$ -	35	59.32%	15,560	53.10%	$ 828	61.30%
15	15	100	*1301-1400*	0	0	0	$ -	35	59.32%	15,560	53.10%	$ 828	61.30%
16	16	100	1401-1500	0	0	0	$ -	35	59.32%	15,560	53.10%	$ 828	61.30%
17	17	500	1501-2000	1	1,639	1,639	$ 66	36	61.02%	17,199	58.70%	$ 895	66.21%
18	18	500	2001-2500	1	2,118	2,118	$ 84	37	62.71%	19,317	65.92%	$ 978	72.40%
19	19	500	2501-3000	0	0	0	$ -	37	62.71%	19,317	65.92%	$ 978	72.40%
20	20		over 3000	2	9,985	9,985	$ 373	39	66.10%	29,302	100.00%	$ 1,351	100.00%
21	**TOTAL**			59	29,302	29,302	$ 1,351						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential NM Service

Description: May 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	25	(81)	(81)	0	25	0.00%	(81)	0.00%	0	0.00%
2	2	100	1-100	5	321	321	$ 53	5	8.33%	240	0.87%	$ 53	3.35%
3	3	100	101-200	3	435	435	$ 42	8	13.33%	675	2.44%	$ 95	6.04%
4	4	100	201-300	6	1,456	1,456	$ 111	14	23.33%	2,131	7.71%	$ 206	13.06%
5	5	100	301-400	4	1,409	1,409	$ 93	18	30.00%	3,540	12.81%	$ 300	18.97%
6	6	100	401-500	2	879	879	$ 54	20	33.33%	4,419	15.99%	$ 354	22.42%
7	7	100	501-600	3	1,626	1,626	$ 95	23	38.33%	6,045	21.87%	$ 449	28.44%
8	8	100	601-700	2	1,297	1,297	$ 73	25	41.67%	7,342	26.57%	$ 522	33.05%
9	9	100	701-800	2	1,505	1,505	$ 82	27	45.00%	8,847	32.01%	$ 604	38.25%
10	10	100	801-900	1	804	804	$ 43	28	46.67%	9,651	34.92%	$ 647	40.99%
11	11	100	901-1000	1	928	928	$ 49	29	48.33%	10,579	38.28%	$ 696	44.08%
12	12	100	1001-1100	2	2,086	2,086	$ 108	31	51.67%	12,665	45.83%	$ 804	50.90%
13	13	100	1101-1200	0	0	0	$ -	31	51.67%	12,665	45.83%	$ 804	50.90%
14	14	100	1201-1300	0	0	0	$ -	31	51.67%	12,665	45.83%	$ 804	50.90%
15	15	100	1301-1400	0	0	0	$ -	31	51.67%	12,665	45.83%	$ 804	50.90%
16	16	100	1401-1500	0	0	0	$ -	31	51.67%	12,665	45.83%	$ 804	50.90%
17	17	500	1501-2000	0	0	0	$ -	31	51.67%	12,665	45.83%	$ 804	50.90%
18	18	500	2001-2500	1	2,139	2,139	$ 108	32	53.33%	14,804	53.57%	$ 912	57.75%
19	19	500	2501-3000	1	2,599	2,599	$ 133	33	55.00%	17,403	62.97%	$ 1,045	66.16%
20	20		over 3000	2	10,233	10,233	$ 534	35	58.33%	27,636	100.00%	$ 1,579	100.00%
21	**TOTAL**			60	27,636	27,636	$ 1,579						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential NM Service

Description: June 2018

USAGE UNIT			*Specify Units*		**ACTUAL**	**BILLED**		**CUMULATIVE BILLED TOTALS**					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	18	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	3	213	213	$ 33	3	5.08%	213	0.48%	$ 33	1.35%
3	3	100	*101-200*	3	547	547	$ 47	6	10.17%	760	1.71%	$ 80	3.30%
4	4	100	*201-300*	6	1,524	1,524	$ 114	12	20.34%	2,284	5.15%	$ 194	8.00%
5	5	100	*301-400*	4	1,349	1,349	$ 91	16	27.12%	3,633	8.20%	$ 285	11.73%
6	6	100	*401-500*	1	428	428	$ 27	17	28.81%	4,061	9.16%	$ 311	12.83%
7	7	100	*501-600*	3	1,692	1,692	$ 98	20	33.90%	5,753	12.98%	$ 409	16.87%
8	8	100	*601-700*	3	1,850	1,850	$ 105	23	38.98%	7,603	17.15%	$ 514	21.20%
9	9	100	*701-800*	2	1,480	1,480	$ 81	25	42.37%	9,083	20.49%	$ 595	24.54%
10	10	100	*801-900*	2	1,630	1,630	$ 88	27	45.76%	10,713	24.17%	$ 683	28.15%
11	11	100	*901-1000*	5	4,722	4,722	$ 247	32	54.24%	15,435	34.82%	$ 930	38.35%
12	12	100	*1001-1100*	0	0	0	$ -	32	54.24%	15,435	34.82%	$ 930	38.35%
13	13	100	*1101-1200*	2	2,315	2,315	$ 118	34	57.63%	17,750	40.04%	$ 1,048	43.21%
14	14	100	*1201-1300*	0	0	0	$ -	34	57.63%	17,750	40.04%	$ 1,048	43.21%
15	15	100	*1301-1400*	0	0	0	$ -	34	57.63%	17,750	40.04%	$ 1,048	43.21%
16	16	100	1401-1500	1	1,442	1,442	$ 71	35	59.32%	19,192	43.30%	$ 1,120	46.16%
17	17	500	1501-2000	2	3,396	3,396	$ 169	37	62.71%	22,588	50.96%	$ 1,289	53.13%
18	18	500	2001-2500	0	0	0	$ -	37	62.71%	22,588	50.96%	$ 1,289	53.13%
19	19	500	2501-3000	0	0	0	$ -	37	62.71%	22,588	50.96%	$ 1,289	53.13%
20	20		over 3000	4	21,740	21,740	$ 1,137	41	69.49%	44,328	100.00%	$ 2,426	100.00%
21	**TOTAL**			59	44,328	44,328	$ 2,426						

Supporting Schedules
As needed

Southwestern Electric Power Company
Docket No. 19-008-U
Test Year Ending December 31, 2018

Schedule H-4
Title: Bill Frequency Analysis
Residential NM Service

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential NM Service

Description: July 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED			CUMULATIVE BILLED TOTALS						
				Number	Metered	Billed	Revenue		Bills		Usage		Revenue		
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block		Number	% of Total	Usage	% of Total		Amount	% of Total
1	1	-	0	15	(135)	(135)		0	15	0.00%	(135)	0.00%		0	0.00%
2	2	100	*1-100*	1	1	1	$	8	1	1.69%	(134)	-0.26%	$	8	0.28%
3	3	100	*101-200*	5	762	762	$	72	6	10.17%	628	1.23%	$	80	2.92%
4	4	100	*201-300*	2	466	466	$	36	8	13.56%	1,094	2.14%	$	116	4.24%
5	5	100	*301-400*	3	968	968	$	66	11	18.64%	2,062	4.04%	$	182	6.64%
6	6	100	*401-500*	4	1,746	1,746	$	108	15	25.42%	3,808	7.46%	$	291	10.59%
7	7	100	*501-600*	1	586	586	$	34	16	27.12%	4,394	8.61%	$	324	11.81%
8	8	100	*601-700*	2	1,265	1,265	$	71	18	30.51%	5,659	11.09%	$	396	14.41%
9	9	100	*701-800*	3	2,251	2,251	$	123	21	35.59%	7,910	15.50%	$	518	18.89%
10	10	100	*801-900*	4	3,448	3,448	$	183	25	42.37%	11,358	22.25%	$	702	25.57%
11	11	100	*901-1000*	4	3,768	3,768	$	198	29	49.15%	15,126	29.63%	$	899	32.77%
12	12	100	*1001-1100*	1	1,059	1,059	$	55	30	50.85%	16,185	31.71%	$	954	34.75%
13	13	100	*1101-1200*	1	1,164	1,164	$	59	31	52.54%	17,349	33.99%	$	1,013	36.91%
14	14	100	*1201-1300*	2	2,502	2,502	$	126	33	55.93%	19,851	38.89%	$	1,139	41.51%
15	15	100	*1301-1400*	4	5,306	5,306	$	266	37	62.71%	25,157	49.29%	$	1,405	51.18%
16	16	100	1401-1500	0	0	0	$	-	37	62.71%	25,157	49.29%	$	1,405	51.18%
17	17	500	1501-2000	2	3,662	3,662	$	183	39	66.10%	28,819	56.46%	$	1,588	57.86%
18	18	500	2001-2500	1	2,279	2,279	$	116	40	67.80%	31,098	60.93%	$	1,704	62.08%
19	19	500	2501-3000	0	0	0	$	-	40	67.80%	31,098	60.93%	$	1,704	62.08%
20	20		over 3000	4	19,943	19,943	$	1,041	44	74.58%	51,041	100.00%	$	2,745	100.00%
21	**TOTAL**			59	51,041	51,041	$	2,745							

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential NM Service

Description: August 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	11	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	0	0	0	$ -	0	0.00%	0	0.00%	$ -	0.00%
3	3	100	*101-200*	1	106	106	$ 12	1	1.69%	106	0.19%	$ 12	0.41%
4	4	100	*201-300*	4	1,007	1,007	$ 76	5	8.47%	1,113	1.97%	$ 88	2.91%
5	5	100	*301-400*	6	2,004	2,004	$ 135	11	18.64%	3,117	5.51%	$ 223	7.38%
6	6	100	*401-500*	5	2,260	2,260	$ 139	16	27.12%	5,377	9.51%	$ 362	11.97%
7	7	100	*501-600*	3	1,678	1,678	$ 97	19	32.20%	7,055	12.48%	$ 459	15.20%
8	8	100	*601-700*	2	1,274	1,274	$ 72	21	35.59%	8,329	14.74%	$ 531	17.57%
9	9	100	*701-800*	1	719	719	$ 40	22	37.29%	9,048	16.01%	$ 570	18.88%
10	10	100	*801-900*	1	878	878	$ 47	23	38.98%	9,926	17.56%	$ 617	20.42%
11	11	100	*901-1000*	7	6,607	6,607	$ 346	30	50.85%	16,533	29.25%	$ 963	31.89%
12	12	100	*1001-1100*	5	5,198	5,198	$ 269	35	59.32%	21,731	38.45%	$ 1,232	40.77%
13	13	100	*1101-1200*	0	0	0	$ -	35	59.32%	21,731	38.45%	$ 1,232	40.77%
14	14	100	*1201-1300*	3	3,715	3,715	$ 187	38	64.41%	25,446	45.02%	$ 1,419	46.98%
15	15	100	*1301-1400*	2	2,711	2,711	$ 135	40	67.80%	28,157	49.82%	$ 1,555	51.46%
16	16	100	1401-1500	1	1,461	1,461	$ 72	41	69.49%	29,618	52.40%	$ 1,627	53.85%
17	17	500	1501-2000	1	1,675	1,675	$ 83	42	71.19%	31,293	55.37%	$ 1,710	56.61%
18	18	500	2001-2500	2	4,383	4,383	$ 222	44	74.58%	35,676	63.12%	$ 1,932	63.96%
19	19	500	2501-3000	0	0	0	$ -	44	74.58%	35,676	63.12%	$ 1,932	63.96%
20	20		over 3000	4	20,843	20,843	$ 1,089	48	81.36%	56,519	100.00%	$ 3,021	100.00%
21	**TOTAL**			59	56,519	56,519	$ 3,021						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential NM Service

Description: September 2018

USAGE UNIT			Specify Units		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	9	(106)	(106)	0	9	0.00%	(106)	0.00%	0	0.00%
2	2	100	1-100	0	0	0	$ -	0	0.00%	(106)	-0.19%	$ -	0.00%
3	3	100	101-200	1	184	184	$ 16	1	1.67%	78	0.14%	$ 16	0.53%
4	4	100	201-300	3	731	731	$ 56	4	6.67%	809	1.44%	$ 71	2.37%
5	5	100	301-400	7	2,333	2,333	$ 157	11	18.33%	3,142	5.60%	$ 229	7.60%
6	6	100	401-500	6	2,597	2,597	$ 161	17	28.33%	5,739	10.23%	$ 390	12.96%
7	7	100	501-600	3	1,745	1,745	$ 100	20	33.33%	7,484	13.34%	$ 490	16.30%
8	8	100	601-700	3	1,922	1,922	$ 108	23	38.33%	9,406	16.77%	$ 599	19.89%
9	9	100	701-800	3	2,172	2,172	$ 119	26	43.33%	11,578	20.64%	$ 718	23.85%
10	10	100	801-900	5	4,254	4,254	$ 227	31	51.67%	15,832	28.22%	$ 945	31.39%
11	11	100	901-1000	3	2,824	2,824	$ 148	34	56.67%	18,656	33.26%	$ 1,093	36.31%
12	12	100	1001-1100	3	3,123	3,123	$ 161	37	61.67%	21,779	38.82%	$ 1,254	41.66%
13	13	100	1101-1200	1	1,126	1,126	$ 58	38	63.33%	22,905	40.83%	$ 1,312	43.58%
14	14	100	1201-1300	0	0	0	$ -	38	63.33%	22,905	40.83%	$ 1,312	43.58%
15	15	100	1301-1400	3	4,049	4,049	$ 202	41	68.33%	26,954	48.05%	$ 1,514	50.29%
16	16	100	1401-1500	1	1,450	1,450	$ 72	42	70.00%	28,404	50.63%	$ 1,586	52.68%
17	17	500	1501-2000	3	4,664	4,664	$ 231	45	75.00%	33,068	58.95%	$ 1,817	60.35%
18	18	500	2001-2500	2	4,177	4,177	$ 211	47	78.33%	37,245	66.40%	$ 2,028	67.36%
19	19	500	2501-3000	0	0	0	$ -	47	78.33%	37,245	66.40%	$ 2,028	67.36%
20	20		over 3000	4	18,851	18,851	$ 982	51	85.00%	56,096	100.00%	$ 3,010	100.00%
21	**TOTAL**			60	56,096	56,096	$ 3,010						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential NM Service

Description: October 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	8	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	3	119	119	$ 28	3	4.92%	119	0.24%	$ 28	1.27%
3	3	100	*101-200*	2	381	381	$ 29	5	8.20%	500	1.02%	$ 57	2.62%
4	4	100	*201-300*	5	1,323	1,323	$ 86	10	16.39%	1,823	3.73%	$ 143	6.61%
5	5	100	*301-400*	7	2,361	2,361	$ 139	17	27.87%	4,184	8.57%	$ 282	13.04%
6	6	100	*401-500*	7	3,180	3,180	$ 168	24	39.34%	7,364	15.08%	$ 450	20.83%
7	7	100	*501-600*	2	1,141	1,141	$ 56	26	42.62%	8,505	17.42%	$ 506	23.44%
8	8	100	*601-700*	4	2,659	2,659	$ 126	30	49.18%	11,164	22.87%	$ 632	29.29%
9	9	100	*701-800*	3	2,266	2,266	$ 104	33	54.10%	13,430	27.51%	$ 737	34.12%
10	10	100	*801-900*	3	2,518	2,518	$ 113	36	59.02%	15,948	32.67%	$ 850	39.38%
11	11	100	*901-1000*	5	4,630	4,630	$ 205	41	67.21%	20,578	42.15%	$ 1,054	48.85%
12	12	100	*1001-1100*	0	0	0	$ -	41	67.21%	20,578	42.15%	$ 1,054	48.85%
13	13	100	*1101-1200*	4	4,653	4,653	$ 198	45	73.77%	25,231	51.68%	$ 1,252	58.00%
14	14	100	*1201-1300*	2	2,545	2,545	$ 107	47	77.05%	27,776	56.90%	$ 1,359	62.94%
15	15	100	*1301-1400*	1	1,357	1,357	$ 56	48	78.69%	29,133	59.68%	$ 1,415	65.55%
16	16	100	1401-1500	0	0	0	$ -	48	78.69%	29,133	59.68%	$ 1,415	65.55%
17	17	500	1501-2000	1	1,854	1,854	$ 74	49	80.33%	30,987	63.47%	$ 1,489	68.99%
18	18	500	2001-2500	0	0	0	$ -	49	80.33%	30,987	63.47%	$ 1,489	68.99%
19	19	500	2501-3000	0	0	0	$ -	49	80.33%	30,987	63.47%	$ 1,489	68.99%
20	20		over 3000	4	17,832	17,832	$ 669	53	86.89%	48,819	100.00%	$ 2,158	100.00%
21	**TOTAL**			61	48,819	48,819	$ 2,158						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential NM Service

Description: November 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	9	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	7	373	373	$ 68	7	9.59%	373	0.96%	$ 68	3.58%
3	3	100	*101-200*	5	730	730	$ 65	12	16.44%	1,103	2.84%	$ 132	7.01%
4	4	100	*201-300*	12	3,093	3,093	$ 204	24	32.88%	4,196	10.79%	$ 336	17.80%
5	5	100	*301-400*	6	2,122	2,122	$ 122	30	41.10%	6,318	16.24%	$ 459	24.28%
6	6	100	*401-500*	5	2,249	2,249	$ 119	35	47.95%	8,567	22.02%	$ 578	30.60%
7	7	100	*501-600*	7	3,969	3,969	$ 196	42	57.53%	12,536	32.22%	$ 774	40.99%
8	8	100	*601-700*	4	2,534	2,534	$ 122	46	63.01%	15,070	38.74%	$ 896	47.44%
9	9	100	*701-800*	2	1,542	1,542	$ 71	48	65.75%	16,612	42.70%	$ 967	51.18%
10	10	100	*801-900*	2	1,721	1,721	$ 77	50	68.49%	18,333	47.12%	$ 1,044	55.26%
11	11	100	*901-1000*	2	1,853	1,853	$ 82	52	71.23%	20,186	51.89%	$ 1,126	59.60%
12	12	100	*1001-1100*	5	5,278	5,278	$ 228	57	78.08%	25,464	65.45%	$ 1,353	71.65%
13	13	100	*1101-1200*	1	1,186	1,186	$ 50	58	79.45%	26,650	68.50%	$ 1,404	74.31%
14	14	100	*1201-1300*	1	1,287	1,287	$ 54	59	80.82%	27,937	71.81%	$ 1,457	77.16%
15	15	100	*1301-1400*	1	1,377	1,377	$ 57	60	82.19%	29,314	75.35%	$ 1,514	80.18%
16	16	100	1401-1500	0	0	0	$ -	60	82.19%	29,314	75.35%	$ 1,514	80.18%
17	17	500	1501-2000	2	3,132	3,132	$ 128	62	84.93%	32,446	83.40%	$ 1,642	86.94%
18	18	500	2001-2500	0	0	0	$ -	62	84.93%	32,446	83.40%	$ 1,642	86.94%
19	19	500	2501-3000	1	2,769	2,769	$ 107	63	86.30%	35,215	90.52%	$ 1,749	92.60%
20	20		over 3000	1	3,690	3,690	$ 140	64	87.67%	38,905	100.00%	$ 1,889	100.00%
21	**TOTAL**			73	38,905	38,905	$ 1,889						

Supporting Schedules
As needed

Southwestern Electric Power Company
Docket No. 19-008-U
Test Year Ending December 31, 2018

Schedule H-4
Title: Bill Frequency Analysis
Residential NM Service

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential NM Service

Description: December 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	9	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	3	169	169	$ 29	3	3.85%	169	0.29%	$ 29	1.11%
3	3	100	*101-200*	2	306	306	$ 26	5	6.41%	475	0.81%	$ 56	2.12%
4	4	100	*201-300*	7	1,800	1,800	$ 119	12	15.38%	2,275	3.88%	$ 174	6.62%
5	5	100	*301-400*	14	4,954	4,954	$ 286	26	33.33%	7,229	12.32%	$ 460	17.47%
6	6	100	*401-500*	2	920	920	$ 48	28	35.90%	8,149	13.89%	$ 509	19.30%
7	7	100	*501-600*	4	2,178	2,178	$ 109	32	41.03%	10,327	17.60%	$ 618	23.44%
8	8	100	*601-700*	5	3,251	3,251	$ 155	37	47.44%	13,578	23.14%	$ 773	29.33%
9	9	100	*701-800*	4	3,007	3,007	$ 139	41	52.56%	16,585	28.27%	$ 911	34.59%
10	10	100	*801-900*	3	2,530	2,530	$ 114	44	56.41%	19,115	32.58%	$ 1,025	38.91%
11	11	100	*901-1000*	2	1,943	1,943	$ 85	46	58.97%	21,058	35.89%	$ 1,110	42.14%
12	12	100	*1001-1100*	3	3,042	3,042	$ 132	49	62.82%	24,100	41.07%	$ 1,243	47.15%
13	13	100	*1101-1200*	2	2,305	2,305	$ 98	51	65.38%	26,405	45.00%	$ 1,341	50.87%
14	14	100	*1201-1300*	2	2,530	2,530	$ 106	53	67.95%	28,935	49.31%	$ 1,447	54.89%
15	15	100	*1301-1400*	5	6,756	6,756	$ 281	58	74.36%	35,691	60.83%	$ 1,727	65.54%
16	16	100	1401-1500	2	2,875	2,875	$ 118	60	76.92%	38,566	65.73%	$ 1,846	70.04%
17	17	500	1501-2000	6	10,445	10,445	$ 420	66	84.62%	49,011	83.53%	$ 2,266	85.99%
18	18	500	2001-2500	1	2,016	2,016	$ 80	67	85.90%	51,027	86.97%	$ 2,346	89.02%
19	19	500	2501-3000	1	2,910	2,910	$ 112	68	87.18%	53,937	91.93%	$ 2,458	93.27%
20	20		over 3000	1	4,737	4,737	$ 177	69	88.46%	58,674	100.00%	$ 2,635	100.00%
21	**TOTAL**			78	58,674	58,674	$ 2,635						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Service R-2

Description: January 2018

USAGE UNIT			*Specify Units*		**ACTUAL**	**BILLED**		**CUMULATIVE BILLED TOTALS**					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	0	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	3,654	162,823	162,823	$ 34,148	3,654	4.17%	162,823	0.16%	$ 34,148	0.81%
3	3	100	*101-200*	3,081	468,216	468,216	$ 40,640	6,735	7.69%	631,039	0.64%	$ 74,787	1.78%
4	4	100	*201-300*	4,155	1,054,210	1,054,210	$ 69,942	10,890	12.43%	1,685,249	1.71%	$ 144,729	3.44%
5	5	100	*301-400*	5,482	1,930,468	1,930,468	$ 111,596	16,372	18.68%	3,615,717	3.66%	$ 256,326	6.09%
6	6	100	*401-500*	6,480	2,922,848	2,922,848	$ 154,858	22,852	26.08%	6,538,565	6.63%	$ 411,184	9.76%
7	7	100	*501-600*	6,644	3,656,460	3,656,460	$ 182,392	29,496	33.66%	10,195,025	10.33%	$ 593,576	14.09%
8	8	100	*601-700*	6,452	4,194,301	4,194,301	$ 200,159	35,948	41.02%	14,389,326	14.58%	$ 793,735	18.84%
9	9	100	*701-800*	5,855	4,387,417	4,387,417	$ 202,446	41,803	47.70%	18,776,743	19.03%	$ 996,181	23.65%
10	10	100	*801-900*	5,130	4,361,160	4,361,160	$ 195,887	46,933	53.56%	23,137,903	23.45%	$ 1,192,068	28.30%
11	11	100	*901-1000*	4,580	4,347,621	4,347,621	$ 191,140	51,513	58.78%	27,485,524	27.85%	$ 1,383,208	32.84%
12	12	100	*1001-1100*	3,968	4,165,259	4,165,259	$ 179,868	55,481	63.31%	31,650,783	32.07%	$ 1,563,076	37.11%
13	13	100	*1101-1200*	3,435	3,945,704	3,945,704	$ 167,877	58,916	67.23%	35,596,487	36.07%	$ 1,730,953	41.09%
14	14	100	*1201-1300*	3,013	3,765,339	3,765,339	$ 158,150	61,929	70.67%	39,361,826	39.88%	$ 1,889,103	44.85%
15	15	100	*1301-1400*	2,641	3,565,380	3,565,380	$ 148,108	64,570	73.68%	42,927,206	43.50%	$ 2,037,211	48.36%
16	16	100	1401-1500	2,302	3,337,016	3,337,016	$ 137,306	66,872	76.31%	46,264,222	46.88%	$ 2,174,517	51.62%
17	17	500	1501-2000	8,159	14,079,503	14,079,503	$ 567,278	75,031	85.62%	60,343,725	61.14%	$ 2,741,796	65.09%
18	18	500	2001-2500	4,841	10,799,045	10,799,045	$ 424,124	79,872	91.14%	71,142,770	72.09%	$ 3,165,919	75.16%
19	19	500	2501-3000	2,986	8,142,029	8,142,029	$ 314,626	82,858	94.55%	79,284,799	80.34%	$ 3,480,545	82.63%
20	20		over 3000	4,777	19,404,941	19,404,941	$ 731,719	87,635	100.00%	98,689,740	100.00%	$ 4,212,264	100.00%
21	**TOTAL**			87,635	98,689,740	98,689,740	$ 4,212,264						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Service R-2

Description: February 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	0	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	4,077	181,545	181,545	$ 38,096	4,077	4.65%	181,545	0.22%	$ 38,096	1.04%
3	3	100	*101-200*	3,761	573,562	573,562	$ 49,681	7,838	8.94%	755,107	0.90%	$ 87,777	2.39%
4	4	100	*201-300*	5,347	1,355,532	1,355,532	$ 89,967	13,185	15.04%	2,110,639	2.52%	$ 177,745	4.84%
5	5	100	*301-400*	7,288	2,568,697	2,568,697	$ 148,441	20,473	23.36%	4,679,336	5.60%	$ 326,186	8.88%
6	6	100	*401-500*	8,090	3,648,200	3,648,200	$ 193,303	28,563	32.59%	8,327,536	9.96%	$ 519,489	14.15%
7	7	100	*501-600*	7,723	4,248,500	4,248,500	$ 211,950	36,286	41.40%	12,576,036	15.04%	$ 731,439	19.92%
8	8	100	*601-700*	6,886	4,472,101	4,472,101	$ 213,468	43,172	49.25%	17,048,137	20.39%	$ 944,906	25.73%
9	9	100	*701-800*	6,012	4,503,600	4,503,600	$ 207,822	49,184	56.11%	21,551,737	25.78%	$ 1,152,728	31.39%
10	10	100	*801-900*	5,026	4,267,905	4,267,905	$ 191,743	54,210	61.85%	25,819,642	30.89%	$ 1,344,471	36.61%
11	11	100	*901-1000*	4,308	4,089,861	4,089,861	$ 179,804	58,518	66.76%	29,909,503	35.78%	$ 1,524,275	41.51%
12	12	100	*1001-1100*	3,548	3,720,472	3,720,472	$ 160,690	62,066	70.81%	33,629,975	40.23%	$ 1,684,965	45.89%
13	13	100	*1101-1200*	3,081	3,543,020	3,543,020	$ 150,718	65,147	74.33%	37,172,995	44.47%	$ 1,835,682	49.99%
14	14	100	*1201-1300*	2,644	3,302,781	3,302,781	$ 138,731	67,791	77.34%	40,475,776	48.42%	$ 1,974,413	53.77%
15	15	100	*1301-1400*	2,310	3,114,459	3,114,459	$ 129,400	70,101	79.98%	43,590,235	52.14%	$ 2,103,813	57.29%
16	16	100	1401-1500	2,012	2,917,460	2,917,460	$ 120,038	72,113	82.27%	46,507,695	55.63%	$ 2,223,851	60.56%
17	17	500	1501-2000	6,767	11,674,549	11,674,549	$ 470,393	78,880	89.99%	58,182,244	69.60%	$ 2,694,244	73.37%
18	18	500	2001-2500	3,816	8,506,684	8,506,684	$ 334,113	82,696	94.35%	66,688,928	79.77%	$ 3,028,358	82.47%
19	19	500	2501-3000	2,204	6,002,507	6,002,507	$ 231,971	84,900	96.86%	72,691,435	86.95%	$ 3,260,328	88.79%
20	20		over 3000	2,750	10,906,755	10,906,755	$ 411,774	87,650	100.00%	83,598,190	100.00%	$ 3,672,103	100.00%
21	**TOTAL**			87,650	83,598,190	83,598,190	$ 3,672,103						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Service R-2

Description: March 2018

USAGE UNIT			Specify Units		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	0	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	4,993	227,334	227,334	$ 46,834	4,993	5.68%	227,334	0.35%	$ 46,834	1.56%
3	3	100	*101-200*	4,886	750,312	750,312	$ 64,728	9,879	11.23%	977,646	1.51%	$ 111,562	3.72%
4	4	100	*201-300*	7,316	1,856,709	1,856,709	$ 123,169	17,195	19.55%	2,834,355	4.39%	$ 234,731	7.84%
5	5	100	*301-400*	9,318	3,280,620	3,280,620	$ 189,661	26,513	30.15%	6,114,975	9.46%	$ 424,392	14.17%
6	6	100	*401-500*	9,730	4,381,822	4,381,822	$ 232,277	36,243	41.21%	10,496,797	16.24%	$ 656,669	21.92%
7	7	100	*501-600*	9,018	4,953,776	4,953,776	$ 247,235	45,261	51.46%	15,450,573	23.90%	$ 903,903	30.18%
8	8	100	*601-700*	7,532	4,886,802	4,886,802	$ 233,321	52,793	60.03%	20,337,375	31.47%	$ 1,137,224	37.96%
9	9	100	*701-800*	6,252	4,680,493	4,680,493	$ 216,015	59,045	67.14%	25,017,868	38.71%	$ 1,353,238	45.18%
10	10	100	*801-900*	5,032	4,272,125	4,272,125	$ 191,940	64,077	72.86%	29,289,993	45.32%	$ 1,545,179	51.58%
11	11	100	*901-1000*	4,080	3,873,135	3,873,135	$ 170,278	68,157	77.50%	33,163,128	51.31%	$ 1,715,457	57.27%
12	12	100	*1001-1100*	3,252	3,410,484	3,410,484	$ 147,298	71,409	81.19%	36,573,612	56.59%	$ 1,862,755	62.18%
13	13	100	*1101-1200*	2,666	3,062,468	3,062,468	$ 130,298	74,075	84.23%	39,636,080	61.32%	$ 1,993,053	66.53%
14	14	100	*1201-1300*	2,272	2,836,812	2,836,812	$ 119,166	76,347	86.81%	42,472,892	65.71%	$ 2,112,219	70.51%
15	15	100	*1301-1400*	1,906	2,569,093	2,569,093	$ 106,745	78,253	88.98%	45,041,985	69.69%	$ 2,218,964	74.08%
16	16	100	1401-1500	1,565	2,265,292	2,265,292	$ 93,226	79,818	90.76%	47,307,277	73.19%	$ 2,312,190	77.19%
17	17	500	1501-2000	4,677	8,002,651	8,002,651	$ 322,742	84,495	96.07%	55,309,928	85.57%	$ 2,634,932	87.96%
18	18	500	2001-2500	1,924	4,267,851	4,267,851	$ 167,700	86,419	98.26%	59,577,779	92.18%	$ 2,802,632	93.56%
19	19	500	2501-3000	813	2,206,641	2,206,641	$ 85,299	87,232	99.19%	61,784,420	95.59%	$ 2,887,930	96.41%
20	20		over 3000	716	2,850,386	2,850,386	$ 107,593	87,948	100.00%	64,634,806	100.00%	$ 2,995,523	100.00%
21	**TOTAL**			87,948	64,634,806	64,634,806	$ 2,995,523						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Service R-2

Description: April 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	0	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	5,323	244,387	244,387	$ 50,002	5,323	6.03%	244,387	0.42%	$ 50,002	1.79%
3	3	100	*101-200*	4,961	760,552	760,552	$ 65,676	10,284	11.66%	1,004,939	1.71%	$ 115,678	4.15%
4	4	100	*201-300*	7,722	1,958,051	1,958,051	$ 129,944	18,006	20.41%	2,962,990	5.05%	$ 245,622	8.82%
5	5	100	*301-400*	9,956	3,505,034	3,505,034	$ 202,639	27,962	31.70%	6,468,024	11.01%	$ 448,261	16.09%
6	6	100	*401-500*	10,381	4,674,419	4,674,419	$ 247,797	38,343	43.46%	11,142,443	18.97%	$ 696,058	24.98%
7	7	100	*501-600*	9,619	5,285,660	5,285,660	$ 263,774	47,962	54.37%	16,428,103	27.98%	$ 959,832	34.45%
8	8	100	*601-700*	8,115	5,269,135	5,269,135	$ 251,526	56,077	63.57%	21,697,238	36.95%	$ 1,211,358	43.48%
9	9	100	*701-800*	6,525	4,885,406	4,885,406	$ 225,466	62,602	70.96%	26,582,644	45.27%	$ 1,436,824	51.57%
10	10	100	*801-900*	5,325	4,520,128	4,520,128	$ 203,089	67,927	77.00%	31,102,772	52.97%	$ 1,639,913	58.86%
11	11	100	*901-1000*	4,185	3,970,279	3,970,279	$ 174,570	72,112	81.74%	35,073,051	59.73%	$ 1,814,483	65.13%
12	12	100	*1001-1100*	3,318	3,481,435	3,481,435	$ 150,350	75,430	85.51%	38,554,486	65.66%	$ 1,964,833	70.53%
13	13	100	*1101-1200*	2,640	3,033,619	3,033,619	$ 129,064	78,070	88.50%	41,588,105	70.82%	$ 2,093,897	75.16%
14	14	100	*1201-1300*	2,073	2,588,706	2,588,706	$ 108,741	80,143	90.85%	44,176,811	75.23%	$ 2,202,638	79.06%
15	15	100	*1301-1400*	1,666	2,248,666	2,248,666	$ 93,414	81,809	92.74%	46,425,477	79.06%	$ 2,296,052	82.42%
16	16	100	1401-1500	1,285	1,860,471	1,860,471	$ 76,564	83,094	94.19%	48,285,948	82.23%	$ 2,372,615	85.16%
17	17	500	1501-2000	3,350	5,710,042	5,710,042	$ 230,382	86,444	97.99%	53,995,990	91.95%	$ 2,602,997	93.43%
18	18	500	2001-2500	1,075	2,372,675	2,372,675	$ 93,273	87,519	99.21%	56,368,665	95.99%	$ 2,696,270	96.78%
19	19	500	2501-3000	369	1,001,816	1,001,816	$ 38,725	87,888	99.63%	57,370,481	97.70%	$ 2,734,995	98.17%
20	20		over 3000	329	1,351,851	1,351,851	$ 50,946	88,217	100.00%	58,722,332	100.00%	$ 2,785,941	100.00%
21	**TOTAL**			88,217	58,722,332	58,722,332	$ 2,785,941						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Service R-2

Description: May 2018

USAGE UNIT			*Specify Units*		**ACTUAL**	**BILLED**		**CUMULATIVE BILLED TOTALS**					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	0	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	5,540	249,886	249,886	$ 53,980	5,540	6.26%	249,886	0.42%	$ 53,980	1.61%
3	3	100	*101-200*	5,063	774,903	774,903	$ 73,489	10,603	11.98%	1,024,789	1.71%	$ 127,469	3.79%
4	4	100	*201-300*	7,358	1,864,218	1,864,218	$ 139,423	17,961	20.29%	2,889,007	4.82%	$ 266,892	7.94%
5	5	100	*301-400*	9,097	3,197,722	3,197,722	$ 211,841	27,058	30.56%	6,086,729	10.16%	$ 478,733	14.25%
6	6	100	*401-500*	9,646	4,341,884	4,341,884	$ 266,668	36,704	41.46%	10,428,613	17.40%	$ 745,401	22.18%
7	7	100	*501-600*	9,157	5,036,467	5,036,467	$ 293,579	45,861	51.80%	15,465,080	25.81%	$ 1,038,979	30.92%
8	8	100	*601-700*	8,307	5,391,283	5,391,283	$ 302,674	54,168	61.19%	20,856,363	34.80%	$ 1,341,653	39.93%
9	9	100	*701-800*	6,956	5,209,640	5,209,640	$ 284,175	61,124	69.04%	26,066,003	43.50%	$ 1,625,828	48.39%
10	10	100	*801-900*	5,774	4,900,482	4,900,482	$ 261,350	66,898	75.57%	30,966,485	51.67%	$ 1,887,178	56.17%
11	11	100	*901-1000*	4,718	4,475,738	4,475,738	$ 234,392	71,616	80.90%	35,442,223	59.14%	$ 2,121,570	63.14%
12	12	100	*1001-1100*	3,681	3,858,125	3,858,125	$ 199,057	75,297	85.05%	39,300,348	65.58%	$ 2,320,627	69.07%
13	13	100	*1101-1200*	3,008	3,458,675	3,458,675	$ 176,185	78,305	88.45%	42,759,023	71.35%	$ 2,496,813	74.31%
14	14	100	*1201-1300*	2,244	2,802,441	2,802,441	$ 141,259	80,549	90.99%	45,561,464	76.03%	$ 2,638,071	78.51%
15	15	100	*1301-1400*	1,700	2,290,605	2,290,605	$ 114,420	82,249	92.91%	47,852,069	79.85%	$ 2,752,491	81.92%
16	16	100	1401-1500	1,323	1,915,926	1,915,926	$ 94,937	83,572	94.40%	49,767,995	83.05%	$ 2,847,428	84.75%
17	17	500	1501-2000	3,318	5,637,038	5,637,038	$ 280,944	86,890	98.15%	55,405,033	92.45%	$ 3,128,372	93.11%
18	18	500	2001-2500	943	2,075,408	2,075,408	$ 105,122	87,833	99.21%	57,480,441	95.92%	$ 3,233,494	96.24%
19	19	500	2501-3000	336	914,146	914,146	$ 46,783	88,169	99.59%	58,394,587	97.44%	$ 3,280,277	97.63%
20	20		over 3000	360	1,533,171	1,533,171	$ 79,693	88,529	100.00%	59,927,758	100.00%	$ 3,359,970	100.00%
21	**TOTAL**			88,529	59,927,758	59,927,758	$ 3,359,970						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Service R-2

Description: June 2018

USAGE UNIT			*Specify Units*		**ACTUAL**	**BILLED**		**CUMULATIVE BILLED TOTALS**					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	0	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	4,313	190,350	190,350	$ 41,839	4,313	4.84%	190,350	0.20%	$ 41,839	0.84%
3	3	100	*101-200*	3,151	473,080	473,080	$ 45,330	7,464	8.38%	663,430	0.70%	$ 87,170	1.75%
4	4	100	*201-300*	3,555	895,804	895,804	$ 67,146	11,019	12.37%	1,559,234	1.65%	$ 154,315	3.10%
5	5	100	*301-400*	4,303	1,511,810	1,511,810	$ 100,170	15,322	17.20%	3,071,044	3.25%	$ 254,486	5.11%
6	6	100	*401-500*	4,901	2,211,079	2,211,079	$ 135,712	20,223	22.70%	5,282,123	5.60%	$ 390,198	7.84%
7	7	100	*501-600*	5,251	2,894,661	2,894,661	$ 168,639	25,474	28.59%	8,176,784	8.67%	$ 558,837	11.23%
8	8	100	*601-700*	5,653	3,679,090	3,679,090	$ 206,427	31,127	34.94%	11,855,874	12.56%	$ 765,264	15.38%
9	9	100	*701-800*	5,848	4,389,611	4,389,611	$ 239,343	36,975	41.50%	16,245,485	17.22%	$ 1,004,607	20.19%
10	10	100	*801-900*	5,687	4,837,022	4,837,022	$ 257,871	42,662	47.89%	21,082,507	22.34%	$ 1,262,477	25.37%
11	11	100	*901-1000*	5,485	5,214,231	5,214,231	$ 272,978	48,147	54.04%	26,296,738	27.87%	$ 1,535,455	30.85%
12	12	100	*1001-1100*	5,155	5,413,544	5,413,544	$ 279,230	53,302	59.83%	31,710,282	33.60%	$ 1,814,685	36.47%
13	13	100	*1101-1200*	4,838	5,561,972	5,561,972	$ 283,334	58,140	65.26%	37,272,254	39.50%	$ 2,098,019	42.16%
14	14	100	*1201-1300*	4,233	5,289,939	5,289,939	$ 266,621	62,373	70.01%	42,562,193	45.10%	$ 2,364,640	47.52%
15	15	100	*1301-1400*	4,000	5,394,454	5,394,454	$ 269,435	66,373	74.50%	47,956,647	50.82%	$ 2,634,075	52.93%
16	16	100	1401-1500	3,329	4,827,070	4,827,070	$ 239,156	69,702	78.24%	52,783,717	55.94%	$ 2,873,231	57.74%
17	17	500	1501-2000	10,995	18,895,931	18,895,931	$ 942,523	80,697	90.58%	71,679,648	75.96%	$ 3,815,754	76.68%
18	18	500	2001-2500	4,663	10,318,217	10,318,217	$ 522,782	85,360	95.81%	81,997,865	86.89%	$ 4,338,535	87.18%
19	19	500	2501-3000	1,946	5,276,474	5,276,474	$ 269,990	87,306	98.00%	87,274,339	92.49%	$ 4,608,526	92.61%
20	20		over 3000	1,785	7,090,996	7,090,996	$ 367,860	89,091	100.00%	94,365,335	100.00%	$ 4,976,386	100.00%
21	**TOTAL**			89,091	94,365,335	94,365,335	$ 4,976,386						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Service R-2

Description: July 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	0	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	3,921	168,178	168,178	$ 37,821	3,921	4.39%	168,178	0.15%	$ 37,821	0.66%
3	3	100	*101-200*	2,595	386,843	386,843	$ 37,210	6,516	7.29%	555,021	0.50%	$ 75,031	1.31%
4	4	100	*201-300*	2,619	659,180	659,180	$ 49,433	9,135	10.22%	1,214,201	1.10%	$ 124,464	2.17%
5	5	100	*301-400*	3,216	1,133,026	1,133,026	$ 75,004	12,351	13.82%	2,347,227	2.13%	$ 199,468	3.48%
6	6	100	*401-500*	3,689	1,666,709	1,666,709	$ 102,258	16,040	17.95%	4,013,936	3.65%	$ 301,726	5.27%
7	7	100	*501-600*	4,092	2,254,552	2,254,552	$ 131,364	20,132	22.53%	6,268,488	5.70%	$ 433,090	7.56%
8	8	100	*601-700*	4,471	2,907,709	2,907,709	$ 163,171	24,603	27.54%	9,176,197	8.35%	$ 596,261	10.41%
9	9	100	*701-800*	4,807	3,608,531	3,608,531	$ 196,751	29,410	32.92%	12,784,728	11.63%	$ 793,012	13.84%
10	10	100	*801-900*	4,854	4,126,765	4,126,765	$ 220,022	34,264	38.35%	16,911,493	15.38%	$ 1,013,034	17.68%
11	11	100	*901-1000*	5,045	4,796,082	4,796,082	$ 251,086	39,309	43.99%	21,707,575	19.74%	$ 1,264,120	22.07%
12	12	100	*1001-1100*	4,977	5,229,427	5,229,427	$ 269,712	44,286	49.56%	26,937,002	24.50%	$ 1,533,832	26.77%
13	13	100	*1101-1200*	4,889	5,624,459	5,624,459	$ 286,491	49,175	55.04%	32,561,461	29.61%	$ 1,820,323	31.78%
14	14	100	*1201-1300*	4,715	5,895,551	5,895,551	$ 297,125	53,890	60.31%	38,457,012	34.98%	$ 2,117,447	36.96%
15	15	100	*1301-1400*	4,298	5,798,693	5,798,693	$ 289,612	58,188	65.12%	44,255,705	40.25%	$ 2,407,059	42.02%
16	16	100	1401-1500	3,939	5,709,763	5,709,763	$ 282,899	62,127	69.53%	49,965,468	45.44%	$ 2,689,958	46.96%
17	17	500	1501-2000	14,211	24,534,293	24,534,293	$ 1,224,155	76,338	85.44%	74,499,761	67.75%	$ 3,914,113	68.32%
18	18	500	2001-2500	7,016	15,554,764	15,554,764	$ 788,178	83,354	93.29%	90,054,525	81.90%	$ 4,702,290	82.08%
19	19	500	2501-3000	3,121	8,480,448	8,480,448	$ 433,974	86,475	96.78%	98,534,973	89.61%	$ 5,136,264	89.66%
20	20		over 3000	2,876	11,420,591	11,420,591	$ 592,460	89,351	100.00%	109,955,564	100.00%	$ 5,728,724	100.00%
21	**TOTAL**			89,351	109,955,564	109,955,564	$ 5,728,724						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Service R-2

Description: August 2018

USAGE UNIT			*Specify Units*		**ACTUAL**	**BILLED**		**CUMULATIVE BILLED TOTALS**					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	0	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	4,165	180,405	180,405	$ 40,253	4,165	4.64%	180,405	0.18%	$ 40,253	0.75%
3	3	100	*101-200*	2,933	436,386	436,386	$ 42,019	7,098	7.90%	616,791	0.60%	$ 82,272	1.52%
4	4	100	*201-300*	2,966	748,333	748,333	$ 56,063	10,064	11.21%	1,365,124	1.32%	$ 138,334	2.56%
5	5	100	*301-400*	3,618	1,271,201	1,271,201	$ 84,227	13,682	15.23%	2,636,325	2.56%	$ 222,561	4.12%
6	6	100	*401-500*	4,349	1,963,341	1,963,341	$ 120,484	18,031	20.08%	4,599,666	4.46%	$ 343,045	6.36%
7	7	100	*501-600*	4,776	2,633,029	2,633,029	$ 153,394	22,807	25.40%	7,232,695	7.02%	$ 496,439	9.20%
8	8	100	*601-700*	5,169	3,368,627	3,368,627	$ 188,953	27,976	31.15%	10,601,322	10.29%	$ 685,392	12.70%
9	9	100	*701-800*	5,296	3,975,856	3,975,856	$ 216,777	33,272	37.05%	14,577,178	14.15%	$ 902,169	16.72%
10	10	100	*801-900*	5,388	4,581,675	4,581,675	$ 244,267	38,660	43.05%	19,158,853	18.59%	$ 1,146,436	21.24%
11	11	100	*901-1000*	5,272	5,009,703	5,009,703	$ 262,287	43,932	48.92%	24,168,556	23.45%	$ 1,408,723	26.10%
12	12	100	*1001-1100*	4,992	5,243,661	5,243,661	$ 270,458	48,924	54.48%	29,412,217	28.54%	$ 1,679,181	31.11%
13	13	100	*1101-1200*	4,747	5,459,932	5,459,932	$ 278,118	53,671	59.76%	34,872,149	33.84%	$ 1,957,299	36.27%
14	14	100	*1201-1300*	4,580	5,724,332	5,724,332	$ 288,510	58,251	64.86%	40,596,481	39.40%	$ 2,245,810	41.61%
15	15	100	*1301-1400*	4,096	5,528,121	5,528,121	$ 276,087	62,347	69.42%	46,124,602	44.76%	$ 2,521,897	46.73%
16	16	100	1401-1500	3,727	5,403,894	5,403,894	$ 267,736	66,074	73.57%	51,528,496	50.01%	$ 2,789,633	51.69%
17	17	500	1501-2000	12,787	22,033,516	22,033,516	$ 1,099,228	78,861	87.81%	73,562,012	71.39%	$ 3,888,861	72.06%
18	18	500	2001-2500	6,037	13,373,146	13,373,146	$ 677,602	84,898	94.53%	86,935,158	84.37%	$ 4,566,464	84.61%
19	19	500	2501-3000	2,615	7,098,214	7,098,214	$ 363,224	87,513	97.45%	94,033,372	91.25%	$ 4,929,687	91.34%
20	20		over 3000	2,294	9,011,306	9,011,306	$ 467,325	89,807	100.00%	103,044,678	100.00%	$ 5,397,012	100.00%
21	**TOTAL**			89,807	103,044,678	103,044,678	$ 5,397,012						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Service R-2

Description: September 2018

USAGE UNIT			Specify Units		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	0	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	3,785	161,735	161,735	$ 36,482	3,785	4.24%	161,735	0.17%	$ 36,482	0.71%
3	3	100	*101-200*	2,574	387,054	387,054	$ 37,056	6,359	7.13%	548,789	0.56%	$ 73,539	1.43%
4	4	100	*201-300*	2,910	734,184	734,184	$ 55,003	9,269	10.39%	1,282,973	1.31%	$ 128,542	2.51%
5	5	100	*301-400*	3,848	1,359,788	1,359,788	$ 89,925	13,117	14.70%	2,642,761	2.71%	$ 218,467	4.26%
6	6	100	*401-500*	4,730	2,139,512	2,139,512	$ 131,224	17,847	20.00%	4,782,273	4.90%	$ 349,691	6.82%
7	7	100	*501-600*	5,218	2,878,754	2,878,754	$ 167,680	23,065	25.84%	7,661,027	7.85%	$ 517,371	10.09%
8	8	100	*601-700*	5,627	3,663,008	3,663,008	$ 205,514	28,692	32.15%	11,324,035	11.60%	$ 722,885	14.10%
9	9	100	*701-800*	5,832	4,377,513	4,377,513	$ 238,684	34,524	38.68%	15,701,548	16.08%	$ 961,569	18.76%
10	10	100	*801-900*	5,819	4,947,483	4,947,483	$ 263,776	40,343	45.20%	20,649,031	21.15%	$ 1,225,345	23.90%
11	11	100	*901-1000*	5,692	5,409,183	5,409,183	$ 283,199	46,035	51.58%	26,058,214	26.69%	$ 1,508,544	29.43%
12	12	100	*1001-1100*	5,371	5,640,109	5,640,109	$ 290,918	51,406	57.60%	31,698,323	32.46%	$ 1,799,462	35.10%
13	13	100	*1101-1200*	5,150	5,922,209	5,922,209	$ 301,674	56,556	63.37%	37,620,532	38.53%	$ 2,101,137	40.99%
14	14	100	*1201-1300*	4,605	5,756,254	5,756,254	$ 290,115	61,161	68.53%	43,376,786	44.42%	$ 2,391,252	46.65%
15	15	100	*1301-1400*	4,032	5,440,477	5,440,477	$ 271,717	65,193	73.05%	48,817,263	50.00%	$ 2,662,969	51.95%
16	16	100	1401-1500	3,653	5,297,656	5,297,656	$ 262,467	68,846	77.14%	54,114,919	55.42%	$ 2,925,436	57.07%
17	17	500	1501-2000	11,665	20,038,086	20,038,086	$ 999,461	80,511	90.21%	74,153,005	75.94%	$ 3,924,896	76.56%
18	18	500	2001-2500	4,950	10,942,155	10,942,155	$ 554,364	85,461	95.76%	85,095,160	87.15%	$ 4,479,260	87.38%
19	19	500	2501-3000	2,047	5,555,229	5,555,229	$ 284,265	87,508	98.05%	90,650,389	92.84%	$ 4,763,525	92.92%
20	20		over 3000	1,738	6,992,251	6,992,251	$ 362,871	89,246	100.00%	97,642,640	100.00%	$ 5,126,396	100.00%
21	**TOTAL**			89,246	97,642,640	97,642,640	$ 5,126,396						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Service R-2

Description: October 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
				Number	Metered	Billed	Revenue	Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	of Bills By Block	Usage By Block	Usage By Block	By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	0	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	4,440	194,576	194,576	$ 41,376	4,440	4.97%	194,576	0.25%	$ 41,376	1.20%
3	3	100	*101-200*	3,359	508,436	508,436	$ 44,234	7,799	8.73%	703,012	0.91%	$ 85,610	2.48%
4	4	100	*201-300*	4,561	1,155,453	1,155,453	$ 76,713	12,360	13.84%	1,858,465	2.41%	$ 162,323	4.70%
5	5	100	*301-400*	6,000	2,113,560	2,113,560	$ 122,165	18,360	20.56%	3,972,025	5.15%	$ 284,489	8.24%
6	6	100	*401-500*	7,063	3,186,707	3,186,707	$ 168,822	25,423	28.46%	7,158,732	9.28%	$ 453,311	13.12%
7	7	100	*501-600*	7,562	4,165,651	4,165,651	$ 207,736	32,985	36.93%	11,324,383	14.68%	$ 661,047	19.14%
8	8	100	*601-700*	7,461	4,854,025	4,854,025	$ 231,597	40,446	45.28%	16,178,408	20.97%	$ 892,644	25.84%
9	9	100	*701-800*	7,217	5,412,290	5,412,290	$ 249,692	47,663	53.36%	21,590,698	27.99%	$ 1,142,335	33.07%
10	10	100	*801-900*	6,513	5,535,775	5,535,775	$ 248,657	54,176	60.66%	27,126,473	35.16%	$ 1,390,992	40.27%
11	11	100	*901-1000*	6,019	5,715,917	5,715,917	$ 251,277	60,195	67.40%	32,842,390	42.57%	$ 1,642,269	47.55%
12	12	100	*1001-1100*	5,168	5,423,344	5,423,344	$ 234,208	65,363	73.18%	38,265,734	49.60%	$ 1,876,477	54.33%
13	13	100	*1101-1200*	4,323	4,967,768	4,967,768	$ 211,349	69,686	78.02%	43,233,502	56.04%	$ 2,087,826	60.44%
14	14	100	*1201-1300*	3,731	4,660,074	4,660,074	$ 195,746	73,417	82.20%	47,893,576	62.08%	$ 2,283,572	66.11%
15	15	100	*1301-1400*	2,992	4,034,864	4,034,864	$ 167,636	76,409	85.55%	51,928,440	67.31%	$ 2,451,208	70.96%
16	16	100	1401-1500	2,496	3,613,836	3,613,836	$ 148,719	78,905	88.34%	55,542,276	71.99%	$ 2,599,927	75.27%
17	17	500	1501-2000	6,608	11,267,294	11,267,294	$ 454,581	85,513	95.74%	66,809,570	86.60%	$ 3,054,508	88.43%
18	18	500	2001-2500	2,269	5,005,421	5,005,421	$ 196,779	87,782	98.28%	71,814,991	93.09%	$ 3,251,287	94.13%
19	19	500	2501-3000	760	2,063,763	2,063,763	$ 79,773	88,542	99.13%	73,878,754	95.76%	$ 3,331,060	96.44%
20	20		over 3000	774	3,270,307	3,270,307	$ 123,075	89,316	100.00%	77,149,061	100.00%	$ 3,454,135	100.00%
21	**TOTAL**			89,316	77,149,061	77,149,061	$ 3,454,135						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Service R-2

Description: November 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
								Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	Number of Bills By Block	Metered Usage By Block	Billed Usage By Block	Revenue By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	0	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	5,267	242,630	242,630	$ 49,505	5,267	5.89%	242,630	0.40%	$ 49,505	1.73%
3	3	100	*101-200*	4,905	749,793	749,793	$ 64,856	10,172	11.37%	992,423	1.64%	$ 114,362	3.99%
4	4	100	*201-300*	7,413	1,878,100	1,878,100	$ 124,687	17,585	19.66%	2,870,523	4.73%	$ 239,048	8.34%
5	5	100	*301-400*	9,735	3,423,222	3,423,222	$ 197,998	27,320	30.54%	6,293,745	10.37%	$ 437,046	15.25%
6	6	100	*401-500*	10,361	4,669,830	4,669,830	$ 247,478	37,681	42.12%	10,963,575	18.06%	$ 684,524	23.88%
7	7	100	*501-600*	9,621	5,288,169	5,288,169	$ 263,879	47,302	52.87%	16,251,744	26.78%	$ 948,403	33.09%
8	8	100	*601-700*	8,396	5,452,816	5,452,816	$ 260,280	55,698	62.26%	21,704,560	35.76%	$ 1,208,683	42.17%
9	9	100	*701-800*	7,009	5,250,353	5,250,353	$ 242,282	62,707	70.09%	26,954,913	44.41%	$ 1,450,965	50.62%
10	10	100	*801-900*	5,554	4,716,021	4,716,021	$ 211,877	68,261	76.30%	31,670,934	52.18%	$ 1,662,842	58.02%
11	11	100	*901-1000*	4,507	4,272,861	4,272,861	$ 187,898	72,768	81.34%	35,943,795	59.22%	$ 1,850,740	64.57%
12	12	100	*1001-1100*	3,541	3,712,717	3,712,717	$ 160,358	76,309	85.30%	39,656,512	65.34%	$ 2,011,098	70.17%
13	13	100	*1101-1200*	2,727	3,130,957	3,130,957	$ 133,223	79,036	88.34%	42,787,469	70.50%	$ 2,144,320	74.81%
14	14	100	*1201-1300*	2,147	2,679,389	2,679,389	$ 112,561	81,183	90.74%	45,466,858	74.91%	$ 2,256,882	78.74%
15	15	100	*1301-1400*	1,606	2,165,917	2,165,917	$ 89,986	82,789	92.54%	47,632,775	78.48%	$ 2,346,868	81.88%
16	16	100	1401-1500	1,297	1,876,763	1,876,763	$ 77,240	84,086	93.99%	49,509,538	81.57%	$ 2,424,108	84.58%
17	17	500	1501-2000	3,409	5,810,533	5,810,533	$ 234,437	87,495	97.80%	55,320,071	91.15%	$ 2,658,545	92.76%
18	18	500	2001-2500	1,110	2,459,842	2,459,842	$ 96,665	88,605	99.04%	57,779,913	95.20%	$ 2,755,210	96.13%
19	19	500	2501-3000	441	1,195,566	1,195,566	$ 46,219	89,046	99.53%	58,975,479	97.17%	$ 2,801,429	97.74%
20	20		over 3000	418	1,718,590	1,718,590	$ 64,765	89,464	100.00%	60,694,069	100.00%	$ 2,866,194	100.00%
21	**TOTAL**			89,464	60,694,069	60,694,069	$ 2,866,194						

Supporting Schedules
As needed

Explanation: For Residential rate schedule(s) and any other rate schedules for which the Company proposes to change the volumetric blocking, show monthly billed activity and actual consumption, if different, by rate schedule in the format provided. For demand metered customers, show the billed demand in addition to the billed usage. By individual rate schedule, provide data in the block format below with no less than 11 blocks, one of which is zero.

Rate Schedule: Residential Service R-2

Description: December 2018

USAGE UNIT			*Specify Units*		ACTUAL	BILLED		CUMULATIVE BILLED TOTALS					
								Bills		Usage		Revenue	
Line No.	Block Number	Block Size	Usage	Number of Bills By Block	Metered Usage By Block	Billed Usage By Block	Revenue By Block	Number	% of Total	Usage	% of Total	Amount	% of Total
1	1	-	0	0	0	0	0	0	0.00%	0	0.00%	0	0.00%
2	2	100	*1-100*	4,365	195,402	195,402	$ 40,824	4,365	4.86%	195,402	0.24%	$ 40,824	1.12%
3	3	100	*101-200*	3,857	584,306	584,306	$ 50,810	8,222	9.16%	779,708	0.95%	$ 91,634	2.51%
4	4	100	*201-300*	5,170	1,307,007	1,307,007	$ 86,858	13,392	14.92%	2,086,715	2.53%	$ 178,492	4.89%
5	5	100	*301-400*	7,057	2,486,236	2,486,236	$ 143,699	20,449	22.78%	4,572,951	5.54%	$ 322,191	8.83%
6	6	100	*401-500*	8,059	3,635,276	3,635,276	$ 192,600	28,508	31.76%	8,208,227	9.95%	$ 514,792	14.11%
7	7	100	*501-600*	7,996	4,399,527	4,399,527	$ 219,472	36,504	40.66%	12,607,754	15.29%	$ 734,264	20.12%
8	8	100	*601-700*	7,356	4,780,815	4,780,815	$ 228,162	43,860	48.86%	17,388,569	21.08%	$ 962,426	26.38%
9	9	100	*701-800*	6,492	4,868,041	4,868,041	$ 224,589	50,352	56.09%	22,256,610	26.98%	$ 1,187,015	32.53%
10	10	100	*801-900*	5,514	4,684,850	4,684,850	$ 210,451	55,866	62.23%	26,941,460	32.66%	$ 1,397,466	38.30%
11	11	100	*901-1000*	4,700	4,458,987	4,458,987	$ 196,057	60,566	67.47%	31,400,447	38.07%	$ 1,593,523	43.68%
12	12	100	*1001-1100*	3,989	4,184,694	4,184,694	$ 180,727	64,555	71.91%	35,585,141	43.14%	$ 1,774,249	48.63%
13	13	100	*1101-1200*	3,383	3,888,937	3,888,937	$ 165,442	67,938	75.68%	39,474,078	47.86%	$ 1,939,691	53.16%
14	14	100	*1201-1300*	2,837	3,541,647	3,541,647	$ 148,778	70,775	78.84%	43,015,725	52.15%	$ 2,088,469	57.24%
15	15	100	*1301-1400*	2,391	3,227,588	3,227,588	$ 134,078	73,166	81.50%	46,243,313	56.07%	$ 2,222,547	60.92%
16	16	100	1401-1500	2,070	2,999,044	2,999,044	$ 123,408	75,236	83.81%	49,242,357	59.70%	$ 2,345,955	64.30%
17	17	500	1501-2000	6,929	11,946,610	11,946,610	$ 481,388	82,165	91.53%	61,188,967	74.19%	$ 2,827,344	77.49%
18	18	500	2001-2500	3,651	8,114,477	8,114,477	$ 318,794	85,816	95.60%	69,303,444	84.02%	$ 3,146,137	86.23%
19	19	500	2501-3000	1,891	5,150,170	5,150,170	$ 199,031	87,707	97.70%	74,453,614	90.27%	$ 3,345,169	91.69%
20	20		over 3000	2,062	8,027,573	8,027,573	$ 303,368	89,769	100.00%	82,481,187	100.00%	$ 3,648,536	100.00%
21	**TOTAL**			89,769	82,481,187	82,481,187	$ 3,648,536						

Supporting Schedules
As needed

Explanation: Schedule showing (1) a narrative explanation of the sequential steps taken and (2) supporting calculations underlying the derivation of each component of the proposed rates for each rate schedule.

The steps in developing new or updated rates are shown in the narrative below.

1) The first step in developing the proposed rates for each rate schedule is to determine the pro forma test year billing determinants and corresponding present base rate revenues. Pro forma year billing determinants are collected for each rate class and adjustments are applied to determine the total adjusted test year base rate revenue. The unadjusted and adjusted billing determinants and base rate revenue for each class are shown in Schedule E-11.1 and E-11.2.
2) The adjusted billing determinants are used to populate the proof of revenue, Schedule H-2. Present base rate revenue is calculated by applying the rates approved in SWEPCO's last rate case to the adjusted billing determinants. Seasonal adjusted customer counts are used to calculate customer charge revenue. Seasonal adjusted kWh billing units are used to calculate seasonal energy charges. The residential classes include an extra step to split the total seasonal kWh billing determinant into seasonal kWh blocks. A workpaper detailing this process is included as Schedule H-2, Attachment 1. The adjusted seasonal demand (kW) billing determinants are used to determine seasonal demand charge revenue for the rate schedules that include charges associated with monthly billing demand. All revenue associated with each rate component is accumulated to determine total adjusted base rate revenue at present rates. The calculated present base rate revenue is compared with the adjusted base rate revenue shown in Schedule E-11.2. Any slight variation in revenue due to calculated base rate revenue is adjusted by a book-to-bill ratio that is also applied to the proposed base rate revenue to calibrate the calculated base rate revenue to the adjusted pro forma base rate revenue based on company books and forecasted data. Once the base rate revenue has been proved, proposed revenues for each rate class can be determined. The proof of revenue, Schedule H-2, includes the calculation of present and proposed revenue for each rate class.
3) The adjusted billing determinants and revenue, along with other pro forma year information, are used to construct the filed cost-of-service study as described in the direct testimony of SWEPCO witness John O. Aaron. Results from the cost-of-service study, including the class returns at present rates, equalized revenue requirements by class, and the unit cost section, are used in the determination of the proposed rate design.
4) The cost of providing service at an equalized return by class is compared to the class present base rate revenues in the revenue distribution, EXHIBIT JLJ-1, supported by SWEPCO witness Jennifer L. Jackson, to identify a class deficiency or surplus. The revenue distribution is used to mitigate impacts to specific customer classes. The revenue distribution identifies rate classes that can be combined to determine a target revenue requirement change based on customer class groupings. The rate class groupings represent the accumulation of all rate schedules in the family of each major rate class in order to

spread the revenue change equally among classes that are similarly situated. Target rate class proposed revenue requirements are determined in the revenue distribution and proposed rates are determined to recover the target proposed revenue requirement. The revenue distribution process and results are discussed in detail in direct testimony by SWEPCO witness Jennifer L. Jackson.

5) The proposed target revenue requirement for each class is used to calculate the proposed rates for each class. Schedule H-2 shows these calculations, including the sum of the revenue requested from each rate class to equal the total SWEPCO Arkansas retail proposed revenue requirement. In general, the proposed revenue requirement for each customer class, sets the percentage change to be applied to the rate components. The unit cost section was also used as a guide in the determination of the rate components along with the proposed class revenue distribution percentage changes. One of the goals of the rate design process is to develop rates that produce similar rate impacts across a range of usage levels. The proposed pricing of each rate component was adjusted to modify customer bill impacts and to recover the total revenue requirement.
   a. Residential Class: The Residential Class includes residential customers taking service under the basic Residential Service rate schedule and the Electric Heating Appliance Service rate schedule. The residential rate schedules recover the class functional costs to serve through fixed customer charges and variable, seasonal blocked kWh rates. The unit cost for the class as shown in the distribution customer component was used as a guide to determine the proposed customer charge for the class along with the percentage change indicated in the proposed revenue distribution. The customer charge was raised above the unit cost to moderate increases in the per kWh rates in each season. The customer charge was raised to $10, and the remaining revenue requirement was spread among the kWh blocks and seasons to achieve the proposed revenue requirement for the class. The inclining block (over 1,500 kWh) in the on-peak season was increased more than the initial block in the on-peak season in order to encourage conservation in the peak season. The percentage increases applied to the present rates to achieve the proposed rates and resulting revenue are shown in Schedule H-2.
   b. General Service Class: The General Service Class is for commercial loads not exceeding 50 kW. The GS rate schedule has a fixed customer charge, seasonal-based flat kWh rates and a non-seasonal demand charge applied on demand over 6 kW used in each billing month. The customer charge was set at the per customer unit cost for the distribution customer function for the GS rate class, $10.60. The demand charge was moderated from the unit cost and the per-kWh rates were increased proportionally to achieve the total revenue requirement after the customer charge and demand charge revenue change was determined to produce similar rate impacts across a range of usage. The Recreational Night Lighting rate schedule is for off-peak lighting-only service for stadium, ball-park, or other recreational night lighting. The customer charge for this rate schedule is designed to be the same as

the GS customer charge. The kWh charge is also based on the off-peak kWh charge of the GS rate schedule and will be applied year-round.

c. Lighting & Power Class: The Lighting and Power class provides service to commercial and small industrial customers with demand requirements over 50 kW served at either secondary or primary voltage. The LP rate schedule does not have a customer charge but has seasonal kWh and kW rates to recover the revenue requirement for the class. The revenue distribution percentage change for the LP secondary class was applied to the demand and kWh rates for secondary service and the percentage change for the LP primary class was applied to the primary service rates (and the Large Lighting & Power (LLP) primary rates) to achieve the required class revenue requirement as determined by the revenue distribution and to produce similar rate impacts across a range of usage levels.
d. Lighting & Power Time of Use Class: The LP TOU rate schedule is an optional rate schedule for customers having a maximum demand of 500 kW served under either secondary or primary voltages. The TOU rate schedule is structured to encourage customers to shift load requirements from the defined on-peak period to the off-peak period. The LP TOU rate schedule has an on-peak season defined as the months of July, August, and September and within the on-peak season, an on-peak period is defined as 1:00 p.m. to 7:00 p.m., excluding holidays and weekends. The off-peak season is defined as the hours other than on-peak. The proposed revenue distribution indicates that the class requires a larger than system average increase to achieve an equalized return. Each rate component was increased based upon the percentage change as directed by the revenue distribution but modified in consideration of customer bill impacts. The on-peak demand charges were increased to encourage load shifting and the off-peak demand charges were increases to achieve the required revenue requirement.
e. Industrial Class: The industrial class includes service for LLP at transmission voltage and a rate for Pulp & Paper Mill Service. Each industrial rate schedule has demand and energy rates to recover the cost to serve each class. The revenue distribution percentage change for each industrial class was applied to the demand and kWh rates to achieve the required revenue. Please note that each industrial class rate schedule provides service for only one customer; therefore, the individual class data is confidential and redacted from Schedule H-2.
f. Municipal Class: The municipal class includes two rate schedules for non-lighting service to municipal customers. The rate schedules in this class include Municipal Service and Municipal Pumping Service. Each municipal schedule includes a customer charge and flat, seasonal energy rates. Both municipal rate schedules have a non-seasonal minimum demand charge used to calculate monthly minimum bills. The customer charge and minimum bill provisions for the municipal schedules are designed to be the same, so the rates under both schedules are adjusted by the same percentage as directed by the revenue distribution.

g. Lighting Class: The Lighting Class includes lighting service for company-owned street and parkway lighting to municipalities and company-owned lighting service for residential, commercial, and industrial customers for outdoor, area, and private lighting. The lighting rate schedules also include energy-only service for customer-owned lighting facilities. Each schedule includes a monthly fixed rate for lighting services and a monthly facilities rate to recover SWEPCO's investment in customer requested facilities. The cost-of-service study indicates that the lighting classes have a higher than system average rate of return and require a rate decrease. The facilities charges were kept at the same level, while the monthly base rate charges were reduced to achieve the total combined revenue requirement, as directed by the revenue distribution.

h. New offerings for LED lighting fixtures: SWEPCO is requesting approval of new offerings for LED fixtures. The offering will include LED fixtures for municipal street lighting customers and for residential and commercial outdoor lighting service. The proposed LED monthly fixture charge is the combination of two components: 1) a component to recover the cost of generation, transmission, and distribution services and 2) a component for replacement of the fixture and photocell. The functional unit cost workpaper is used to determine a services cost on a per-kWh basis. The per-kWh rate is applied to the monthly average fixed kWh associated with each type of LED fixture. The replacement component is based on the cost to replace the fixture and photocell to be recovered on a monthly basis. In order to facilitate updates to rapidly changing LED technology, SWEPCO is proposing three ranges of LED service defined by lumen output and wattage. The LED ranges will accommodate future additional fixture types and updates to existing lumen output and wattage. Direct testimony EXHIBIT JLJ-4 details the calculation of the proposed LED rates.

i. Additional General Rate Schedules: SWEPCO's Tariff includes several, optional services including Alternate Feed Service (AFS), and optional service for Standby, Backup, Maintenance, and As-Available Standby Power Service. AFS may be available for LP and LLP customers who request alternate feed service from existing distribution facilities in addition to basic service. Standby, Backup, Maintenance, and As-Available Standby Power Service is available to customers that own and operate power production equipment and have a separate agreement for interconnection to SWEPCO's system. The individual rates for each service have been adjusted according to the corresponding class percentage change determined in the revenue distribution. SWEPCO also has charges for highly fluctuating loads and kVAR charges to recover costs associated with reactive demands. The charge for highly fluctuating loads and kVAR can be applied across multiple rate classes; therefore, the present rates for these charges are increased by the total retail percentage change as indicated in the revenue distribution. The AFS rate calculation workpaper is included as Schedule H-5, Attachment 2. The Standby, Backup, Maintenance, and As-Available Standby Power Service

workpaper detailing the rate changes is included as Schedule H-5, Attachment 3. Rate schedules with references to facilities charges and maintenance charges, including the lighting rate schedules and municipal rate schedule, will include a new facilities and maintenance charge percentage based on updated information that will be adjusted based on a final order in this case. The workpaper detailing the calculation of the new facilities and maintenance percentages is included Schedule H-5, Attachment 4.

For additional discussion on the derivation of the proposed rates and supporting calculations underlying the derivation of each component of the proposed rates for each rate schedule, please see the direct testimony of SWEPCO witness Jennifer L. Jackson, including testimony EXHIBIT JLJ-1, the unit cost workpaper supporting the cost-of-service study, and Schedule H-2, the rate class proof of revenues for present and proposed rates. The "Pricing" and "Results" tabs of Schedule H-2 show the derivation of the proposed rates based on the percentage change for each class as proposed in the revenue distribution.

Supporting Schedules:

Schedule H-2 and supporting Schedule H-5 workpapers

Southwestern Electric Power Company
Docket No. 19-008-U
Test Year Ending December 31, 2018

Schedule H-5
Attachment 1
Residential Blocking
Schedule H-2 Supporting Workpaper

ACTUAL UNADJUSTED KWH

							201812	201801	201802	201803	201804	201805	201806	201807	201808	201809	201810	201811	Sum:
SOUTHWE	AR	015	RS	RESIDENTIAL SERVICE	EN30A	ENERGY STEP 1 USAGE * RATE	82,989,813.92	99,712,758.24	84,596,509.78	65,679,494.52	59,633,884.99	57,845,294.64	82,777,485.79	92,248,753.03	88,630,135.66	85,947,240.20	78,038,580.87	61,301,844.18	939,401,795.81
SOUTHWE	AR	015	RS	RESIDENTIAL SERVICE	EN30B	ENERGY STEP 2 USAGE * RATE						2,764,659.37	12,849,063.44	19,601,308.59	16,195,853.73	13,121,366.68			64,532,251.81
												60,609,954	95,626,549	111,850,062	104,825,989	99,068,607			
						ENERGY STEP 1 USAGE * RATE						0.95439	0.86563	0.82475	0.84550	0.86755			
						ENERGY STEP 2 USAGE * RATE						0.04561	0.13437	0.17525	0.15450	0.13245			
												1.00000	1.00000	1.00000	1.00000	1.00000			
SOUTHWE	AR	015	RS	RESIDENTIAL SERVICE	EN30B	TYE 12-31-18						52,665,986	79,276,597	102,034,457	108,783,553	101,494,227			444,254,820
						ENERGY STEP 1 USAGE * RATE						50,263,682	68,624,429	84,153,297	91,976,246	88,051,594			383,069,248
						ENERGY STEP 2 USAGE * RATE						2,402,304	10,652,168	17,881,160	16,807,306	13,442,633			61,185,571
SOUTHWE	AR	038	RS-MUL	RESIDENTIAL-MULTIPLE DWELLIN	EN48A	ENERGY STEP 1 USAGE CHARGE	41,713.00	50,914.00	45,341.00	30,657.00	28,130.00	19,243.00	25,063.00	30,597.00	29,197.00	25,524.00	23,649.00	27,212.00	377,240.00
SOUTHWE	AR	038	RS-MUL	RESIDENTIAL-MULTIPLE DWELLIN	EN48B	ENERGY STEP 2 USAGE CHARGE						0.00	0.00	436.00	0.00	0.00			436.00
												19,243.00	25,063.00	31,033.00	29,197.00	25,524.00			
						ENERGY STEP 1 USAGE * RATE						1.00000	1.00000	0.98595	1.00000	1.00000			
						ENERGY STEP 2 USAGE * RATE						0.00000	0.00000	0.01405	0.00000	0.00000			
												1.00000	1.00000	1.00000	1.00000	1.00000			
SOUTHWE	AR	038	RS-MUL	RESIDENTIAL-MULTIPLE DWELLIN	EN30B	TYE 12-31-18						17,122	21,337	29,240	27,046	25,588			120,332
						ENERGY STEP 1 USAGE * RATE						17,122	21,337	28,829	27,046	25,588			119,922
						ENERGY STEP 2 USAGE * RATE						0	0	411	0	0			411
SOUTHWE	AR	062	RS NET	RESIDENTIAL NET-METERING	EN30A	ENERGY STEP 1 USAGE * RATE	30,775.17	54,910.00	48,066.00	37,221.00	29,317.00	19,852.00	28,203.00	35,666.00	40,125.00	41,910.00	48,825.00	38,991.00	453,861.17
SOUTHWE	AR	062	RS NET	RESIDENTIAL NET-METERING	EN30B	ENERGY STEP 2 USAGE * RATE						9,124.00	16,136.00	15,384.00	16,401.00	14,192.00			71,237.00
												28,976.00	44,339.00	51,050.00	56,526.00	56,102.00			
						ENERGY STEP 1 USAGE * RATE						0.68512	0.63608	0.69865	0.70985	0.74703			
						ENERGY STEP 2 USAGE * RATE						0.31488	0.36392	0.30135	0.29015	0.25297			
												1.00000	1.00000	1.00000	1.00000	1.00000			
SOUTHWE	AR	062	RS NET	RESIDENTIAL NET-METERING	EN30B	TYE 12-31-18						20,910	33,869	42,082	54,403	52,500			203,763
						ENERGY STEP 1 USAGE * RATE						14,326	21,543	29,400	38,618	39,219			143,106
						ENERGY STEP 2 USAGE * RATE						6,584	12,326	12,681	15,785	13,281			60,657
SOUTHWE	AR	022	RS-EH	RESIDENTIAL-ELECTRIC HTG APF	EN30A	ENERGY STEP 1 USAGE * RATE	5,820,456.20	6,488,633.32	6,405,327.88	6,190,295.03	6,115,583.92	10,976,562.00	13,304,807.63	14,169,226.29	13,620,872.86	13,204,639.46	5,761,070.23	5,678,042.49	107,735,517.31
SOUTHWE	AR	022	RS-EH	RESIDENTIAL-ELECTRIC HTG APF	EN30B	ENERGY STEP 2 USAGE * RATE	12,924,049.09	20,653,798.13	16,357,881.80	9,883,088.18	7,340,510.85	875,310.44	2,831,058.65	3,929,812.70	3,417,417.31	2,956,096.95	7,263,371.73	6,511,167.98	94,943,563.80
							18,744,505.29	27,142,431.45	22,763,209.67	16,073,383.22	13,456,094.77	11,851,872.44	16,135,866.27	18,099,038.99	17,038,290.17	16,160,736.41	13,024,441.96	12,189,210.47	202,679,081.11
						ENERGY STEP 1 USAGE * RATE	0.31052	0.23906	0.28139	0.38513	0.45448	0.92615	0.82455	0.78287	0.79943	0.81708	0.44233	0.46583	
						ENERGY STEP 2 USAGE * RATE	0.68948	0.76094	0.71861	0.61487	0.54552	0.07385	0.17545	0.21713	0.20057	0.18292	0.55767	0.53417	
							1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	
SOUTHWE	AR	022	RS-EH	RESIDENTIAL-ELECTRIC HTG APF	EN30B	TYE 12-31-18 MAY - SEPTEMBER						11,045,762	14,609,324	18,174,948	19,576,589	18,492,111			81,898,734
						ENERGY STEP 1 USAGE * RATE		5,761,070.23	5,678,042.49	5,820,456.20		10,229,986	12,046,099	14,228,653	15,650,058	15,109,563			67,264,359
						ENERGY STEP 2 USAGE * RATE		7,263,371.73	6,511,167.98	12,924,049.09		815,776	2,563,225	3,946,295	3,926,531	3,382,548			14,634,375
						TYE 12-31-18 OCTOBER - APRIL	18,608,918	25,307,421	22,920,470	17,849,266	13,787,093						13,223,727	12,372,753	124,069,649
						ENERGY STEP 1 USAGE * RATE	5,778,354	6,049,958	6,449,579	6,874,236	6,266,018						5,849,219	5,763,541	43,030,905
						ENERGY STEP 2 USAGE * RATE	12,830,564	19,257,463	16,470,891	10,975,030	7,521,076						7,374,507	6,609,212	81,038,743
SOUTHWE	AR	039	RS-EH-I	RESIDENTIAL-ELECT HT-MULTI DV	EN48A	ENERGY STEP 1 USAGE CHARGE	18,500.00	18,500.00	18,500.00	18,500.00	18,500.00	53,716.00	44,319.00	45,454.00	44,020.00	54,976.00	18,500.00	18,500.00	371,985.00
SOUTHWE	AR	039	RS-EH-I	RESIDENTIAL-ELECT HT-MULTI DV	EN48B	ENERGY STEP 2 USAGE CHARGE	66,880.00	72,454.00	77,271.00	62,325.00	55,311.00	18,900.00	9,612.00	8,230.00	6,767.00	19,872.00	56,775.00	37,866.00	492,263.00
							85,380.00	90,954.00	95,771.00	80,825.00	73,811.00	72,616.00	53,931.00	53,684.00	50,787.00	74,848.00	75,275.00	56,366.00	864,248.00
						ENERGY STEP 1 USAGE * RATE	0.21668	0.20340	0.19317	0.22889	0.25064	0.73973	0.82177	0.84670	0.86676	0.73450	0.24577	0.32821	
						ENERGY STEP 2 USAGE * RATE	0.78332	0.79660	0.80683	0.77111	0.74936	0.26027	0.17823	0.15330	0.13324	0.26550	0.75423	0.67179	
							1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	
SOUTHWE	AR	039	RS-EH-I	RESIDENTIAL-ELECT HT-MULTI DV	EN48A	TYE 12-31-18 MAY - SEPTEMBER						64,548	45,900	50,582	54,423	79,315			294,768
						ENERGY STEP 1 USAGE * RATE						47,748	37,720	42,827	47,172	58,257			233,724
						ENERGY STEP 2 USAGE * RATE						16,800	8,181	7,754	7,251	21,058			61,044
						TYE 12-31-18 OCTOBER - APRIL	74,778	84,108	95,114	87,728	73,377						70,689	60,373	546,167
						ENERGY STEP 1 USAGE * RATE	16,203	17,107	18,373	20,080	18,391						17,373	19,815	127,342
						ENERGY STEP 2 USAGE * RATE	58,575	67,000	76,741	67,648	54,986						53,316	40,558	418,824

Alternate Feed Service Demand Calculation
Class Cost of Service Study - Test Year December 31, 2018

Account	Description	LLP Primary	LP Primary	Average
580	Supervisory & Engineering	10,395	31,849	21,122
581	Load Dispatch	173	499	336
582	Station Expense	4,308	12,299	8,304
583	OH Lines	16,798	47,955	32,377
584	UG Lines	9,989	28,517	19,253
588	Misc	105,062	303,626	204,344
589	Rents	4,885	14,117	9,501
Total Distribution Operation		151,611	438,863	295,237
Demand @ Primary		344,769	1,349,506	847,137
Operation Rate @ Primary		$0.440	$0.325	$0.349

Account	Description	LLP Primary	LP Primary	Average
590	Supervisory & Engineering	1,845	5,349	3,597
591	Structures	279	797	538
592	Station Equipment	6,873	19,620	13,247
593	OH Lines	222,336	637,824	430,080
594	UG Lines	4,761	13,591	9,176
595	Line Transformers	820	2,341	1,581
Total Distribution Maintenance		236,914	679,523	458,219
Demand @ Primary		344,769	1,349,506	847,137
Maintenance Rate @ Primary		$0.687	$0.504	$0.541

Investment Cost

Account	Description	LLP Primary	LP Primary	Average
360	Land & Land Rights	115,275	329,081	222,178
361	Structures & Improv	104,844	299,304	202,074
362	Station Equipment	3,369,375	9,618,705	6,494,040
364	Poles	2,122,454	6,059,063	4,090,759
365	OH Lines	3,035,138	8,664,545	5,849,842
366	UG Conduit	324,634	926,747	625,690
367	UG Lines	1,131,033	3,228,811	2,179,922
Total Distribution Investment		10,202,754	29,126,255	19,664,504
Demand @ Primary		344,769	1,349,506	847,137
Investment per kW		$29.59	$21.58	$23.21
Distribution Fixed Charge Rate		17.94%	17.94%	17.94%
Monthly Cost per kW		$5.31	$3.87	$4.17

Estimated Rate Calculation	LLP Primary	LP Primary	Average
Operation Cost	$0.440	$0.325	$0.349
Maintenance Cost	0.687	0.504	0.541
Investment Cost	5.310	3.873	4.165
Total Cost per kW	$6.44	$4.70	$5.06

AFS CAPACITY DEMAND CHARGE: $5.06

Supplementary, Backup, Maintenance, and As-Available Standby Power Service

Daily Rate For Backup Power	Current	Proposed		65.82%	68.23%
Pulp&Paper Mill	$0.22	$0.31			
LLP Trans	$0.22	$0.31			
LP Pri	$0.28	$0.46			
LP Sec	$0.30	$0.50			
Daily Rate For Maintenance Power			46.89%		
	Current	Proposed			
Pulp&Paper Mill	$0.12	$0.18			
LLP Trans	$0.12	$0.18			
LP Pri	$0.12	$0.18			
LP Sec	$0.15	$0.22			
Backup Power - Minimum Charge Per kW			46.89%	65.82%	68.23%
	Current	Proposed			
Pulp&Paper Mill	$0.91	$1.33			
LLP Trans	$0.91	$1.33			
LP Pri	$2.55	$4.23			
LP Sec	$2.63	$4.42			
Maintenance Power - Minimum Charge Per kW					
	Current	Proposed	46.89%	65.82%	68.23%
Pulp&Paper Mill	$0.46	$0.68			
LLP Trans	$0.46	$0.68			
LP Pri	$1.27	$2.11			
LP Sec	$1.32	$2.22			
Monthly Rate For As-Available Standby Power					
	Current	Proposed	46.89%	65.82%	68.23%
Pulp&Paper Mill	$0.32	$0.47			
LLP Trans	$0.32	$0.47			
LP Pri	$1.18	$1.96			
LP Sec	$1.21	$2.04			
Pulp & Paper Mill Service					
	Current	Proposed	46.89%		
Emergency kW	$6.66	$9.30	daily rate $0.31*30 days		
Emergency kWh	$0.0152	$0.0223			
Maintenance Power - limited hours	$2.62	$3.85			
Maintenance Power - any time	$5.23	$7.68			
Charge for Highly Fluctuating Loads	$1.00	$1.58	57.69%		
kVAR Charge	$0.34	$0.54			

FACILITIES RENTAL / MAINTENANCE

1 DESCRIPTION OF CHARGE

The Facilities Rental fee is made when Customer rents facilities owned and maintained by Company. Facilities Maintenance fee is charged for maintaining facilities for which a customer has made a contribution in aid for construction or for Company maintenance of customer-owned facilities.

A.) Facilities Rental B.) Facilities Maintenance

2 EXPLANATION OF COST

Calculated monthly levelized fixed charge rate for electric distribution equipment.

3 ESTIMATE OF COST 2017 FERC FORM 1 DATA

Description	Total	A	B
Distribution O & M Expenses	5.41000%	5.41000%	5.4100%
Other Taxes Expenses	1.96000%	1.96000%	1.9600%
Distribution Portion of A&G	0.90000%	0.90000%	0.9000%
Cost of Capital	7.26333%	7.26333%	
Depreciation Expense	1.21290%	1.21290%	
Composite Income Tax Rate	1.34000%	1.34000%	
General Plant Investment & Depr.	0.69000%	0.69000%	
Working Capital	0.08000%	0.08000%	
ADIT Adjustment	-1.32000%	-1.32000%	
Annual Fixed Charge Rate	17.53623%	17.53623%	8.2700%
Monthly Fixed Charge Rate	1.46135%	1.46135%	0.6892%

4 PROPOSED CHARGE	1.46%	1.46%	0.69%

Note: The proposed charge is a placeholder to be updated based on the Final Order in Docket No. 19-008-U

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. TC-1	Sheet 1 of 6	
Replacing:	Sheet No.		
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY			
Kind of Service: Electric			
Title: TABLE OF CONTENTS			PSC File Mark Only

PART I. GENERAL INFORMATION

PART II. EXEMPTION SCHEDULES

PART III. RATE SCHEDULES

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. TC-2	Sheet 2 of 6
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric		
Title: TABLE OF CONTENTS		PSC File Mark Only

PART III. RATE SCHEDULES (Continued)

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. TC-3	Sheet 3 of 6
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric		
Title: TABLE OF CONTENTS		PSC File Mark Only

PART III. RATE SCHEDULES (Continued)

THIS SPACE FOR PSC USE ONLY

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. TC-4	Sheet 4 of 6	
Replacing:	Sheet No.		
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY			
Kind of Service: Electric			
Title: TABLE OF CONTENTS			PSC File Mark Only

PART III. RATE SCHEDULES (Continued)

THIS SPACE FOR PSC USE ONLY

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. TC-5	Sheet 5 of 6
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric		
Title: TABLE OF CONTENTS		PSC File Mark Only

PART III. RATE SCHEDULES (Continued)

PART IV. POLICY SCHEDULES

ARKANSAS PUBLIC SERVICE COMMISSION

PART III. RATE SCHEDULES (Continued)

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. E-1.1 Sheet 1 of 2	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Exemption Schedule No. 1		
Title: EXEMPTION FROM COMMISSION RULES		PSC File Mark Only

General Service Rule 4.01 – Deposits from Applicants

SWEPCO was granted exemption to utilize the computerized system of “Pos ID” in evaluating and identifying the credit risk of new applicants for utility service (Docket #98-056-U).

General Service Rule 4.03B – Calculation of Average Bill – For Inadequate Billing History

SWEPCO was granted exemption from General Service Rule 4.03B by clarifying that the basis on which the deposit for a non-residential applicant is calculated will be determined as following:

“When a non-residential applicant requests service in a location where the previous customer at that location was of the same business type and size as the applicant for service, the average bill shall not be more than the average monthly bill for that location for the most recently completed representative 12-month period.”

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. E-1.2	Sheet 2 of 2
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Exemption Schedule No. 1		
Title: EXEMPTION FROM COMMISSION RULES		PSC File Mark Only

General Service Rule 5.21 – Transferring Past Due Balances to Other Accounts

SWEPCO was granted exemption from General Service Rule 5.21 by the addition of the following Paragraph.

"C. An account of any Customer, of any class, when the Company receives a written request to have a balance transferred to the requesting Customer's account and when the following information is stated in the letter of request:

(1) Name and account number of the Customer requesting that a balance is to be transferred to their account;
(2) Name and account number of the Customer whose balance is to be transferred; and
(3) A statement that the requesting Customer understands that their own service may be terminated for non-payment if the transferred balance is not paid in full in accordance with any agreed upon payment arrangements."

Rules for Conservation and Energy Efficiency – Section 5.D

SWEPCO was granted a waiver of Section 5.D of the Conservation and Energy Efficiency Rules by Order 22 of Docket 07-082-TF. The waiver allows SWEPCO to implement its Commercial and Industrial Standard Offer Program and associated rebates for new construction.

Rules for Conservation and Energy Efficiency – Section 7.D

SWEPCO was granted a waiver of Section 7.D of the Conservation and Energy Efficiency Rules by Order 22 of Docket 07-082-TF. The waiver allows SWEPCO to implement its Emergency Load Management Standard Offer Program as and Energy Efficiency program.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. GI-1.1	Sheet 1 of 1
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. General Information Schedule No. 1		
Title: UTILITY INFORMATION		PSC File Mark Only

Utility Official: Elizabeth D. Stephens
Regulatory Consultant

Telephone Number: (318) 673-3626

Mailing Address: Southwestern Electric Power Company
P. O. Box 21106
428 Travis Street (71101)
Shreveport, LA 71156

E-Mail: edstephens@aep.com

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. GI-2.1 Sheet 1 of 1

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: All

Part III. General Information Schedule No. 2

Title: Reserved for Future Use~~TARIFF FORMAT~~
~~(Rules of Practice & Procedure 11.03 (c))~~

PSC File Mark Only

This Schedule has been removed from the tariff book

Reserved for Future Use

~~The following symbols appear in the margin opposite any revision to the previously approved tariff.~~

~~Symbol~~	~~Explanation~~
~~(DR)~~	~~Discontinued Rate~~
~~(AT)~~	~~Additions to Text~~
~~(RT)~~	~~Removal of Text~~
~~(CR)~~	~~Change in Rate~~
~~(CP)~~	~~Change in Practice~~
~~(CT)~~	~~Change in Text~~
~~(NR)~~	~~New Rate~~
~~(C)~~	~~A Correction~~
~~(MT)~~	~~Move of Text~~

1. APPLICABLE TO ALL CLASSES OF ELECTRIC SERVICE

In order that all Customers may receive uniform, efficient, and adequate service, electric service will be supplied to and accepted by all Customers receiving service from the Company in accordance with these Terms and Conditions.

2. ORDER FOR SERVICE

When applicable, contract and agreement forms are provided by the Company to show the agreement under which the Customer receives and the Company delivers electric service. Appropriate arrangements will be completed with Customer, or his duly-authorized agent, before service is supplied by the Company.

3. OPTIONAL RATES

The Company's published rate schedules state the conditions under which each is available for electric service. When two or more rates are applicable to a certain class of service, the choice of such rates lies with the Customer.

The Company, at any time upon request, will determine for any Customer the rate best adapted to existing or anticipated service requirements as defined by the Customer, but the Company does not assume responsibility for the selection of such rate or for the continuance of the lowest annual cost under the rate selected.

The Company, lacking knowledge of changes that may occur at any time in the Customer's operating conditions, does not assume responsibility that Customer will be served under the most favorable rate; nor will the Company make refunds covering the difference between the charges under the rate in effect and those under any other rate applicable to the same service.

Rates are normally established on a twelve-month basis and a Customer having selected a rate adapted to his service may not change to another rate within a twelve-month period unless there is a substantial change in the character or conditions of his service. A new Customer will be given reasonable opportunity to determine his service requirements before definitely selecting the most favorable rate therefor.

4. MONTHLY BILLS

Bills for service will be rendered monthly, unless otherwise specified. The term "month" for billing purposes will mean the period between any two consecutive readings of the meters by the Company, such readings to be taken as nearly as practicable every thirty days, but no less than 25 days and no more than 35 days.

Failure to receive a bill in no way exempts Customers from payment for electric service.

The Company makes a special effort to read all meters every month. Sometimes due to adverse weather conditions, dog hazards, damaged equipment, etc., it is not possible to obtain a meter reading and the bill may be estimated. Estimated bills are identified on the bill with an applicable code.

5. DISCONTINUANCE OF SERVICE

When bills for electric service are in arrears, or in case the Customer fails to comply with these Terms and Conditions, the Company will have the right to discontinue electric service to the Customer and to remove its property from the Customer's premises upon mailing notice to address to which the monthly bills are sent. There will be a charge for reconnecting the service to Customers whose service has been disconnected for non-payment of bills.

6. EXCLUSIVE SERVICE ON INSTALLATION CONNECTED TO COMPANY'S SYSTEM

Except as may be specifically permitted under tariffs governing the interconnection or provision of service to small power producers or cogenerators, standard electric rate schedules are based on exclusive use of Company's service.

Except in cases where the Customer has a contract with the Company for breakdown or standby service, no other electric light or power service will be used by the Customer on the same installation in conjunction with the Company's service, either by means of a throw-over switch or any other connection.

The Company will not be required to supply or continue to supply service to any Customer where a portion of Customer's service requirement is obtained from other sources, except when such service is covered by a contract.

The Customer will not sell the electricity purchased from the Company to any other customer, company, or person, and Customer will not deliver electricity purchased from the Company to any connection wherein said electricity is to be used off of the Customer's premises on which the meter is located.

7. CUSTOMER'S INSTALLATION

All wiring and other electrical equipment furnished by the Customer will be installed, operated, and maintained by the Customer at all times in conformity with good electrical practice and with the requirements of the constituted authorities and these Terms and Conditions. Where no public authorities have jurisdiction, Company, for Customer's protection, may require Customer to furnish Company a certificate from wiring electrician that Customer's installation conforms to the National Electrical Code and/or the National Electrical Safety Code. The Company does not assume responsibility for the design, operation, or condition of the Customer's installation.

Service will be delivered to Customer for each premise at one point of delivery to be designated by Company and to conform to Company's service standards. For mutual protection of Customer and Company, only authorized employees of Company are permitted to make and energize the connection between Company's service wire and Customer's service entrance conductors.

8. OWNER'S CONSENT TO OCCUPY

The Company shall have the right to install and maintain equipment in, over and under the Customer's property and shall have access to the Customer's premises for any other purpose necessary for supplying electric service to the Customer. In case the Customer is not the owner of the premises or of the intervening property between the premises and the Company's lines, the Customer will obtain from the property owner or owners the easements or right-of-way necessary to install and maintain in, over or under said premises all such

wires and electrical equipment as are necessary or convenient for supplying electric service to the Customer.

9. MOTOR INSTALLATIONS

For mutual protection of service to all customers, all motor installations will be as follows:

(a) All motors rated in horsepower up to and including 7-1/2 HP and individual air conditioning units with ratings of 65,000 BTUH (ARI rating) or less will be single phase, unless otherwise agreed to by the Company or served in conjunction with other larger three phase loads.

(b) All three phase motors will be equipped with approved starting equipment having low voltage release attachment and properly sized over-current protection in each of the three phases.

10. POWER FACTOR

The Company will not be required to furnish electric service to any Customer with low power factor equipment.

Where Customer has power or heating equipment installed that operates at low power factor, Customer, when requested to do so by the Company, will furnish, at his own expense, suitable corrective equipment to maintain a power factor of 90% lagging, or higher.

Customer will install and maintain in conjunction with any fluorescent lighting, neon lighting, or other lighting equipment having similar load characteristics, auxiliary or other

corrective apparatus that will correct the power factor of such lighting equipment to not less than 90% lagging.

<u>11. PROTECTION OF SERVICE</u>

The Company will not be obligated to serve any devices that have a detrimental effect upon the service rendered to other Customers or upon Company equipment. Where the Customer's use of such a device causes voltage fluctuation of the 60 Hertz wave, clipping of the current, or voltage wave - thereby producing harmonics or a cyclic pulsation between one and sixty Hertz (1 and 60 Hertz), Customer will furnish at his own expense necessary equipment to limit such voltage fluctuation, harmonics, or pulsations so that they will not interfere with other Customers or Company equipment. Where the interference cannot be corrected, the use of such devices must be discontinued.

<u>12. CONTINUOUS SERVICE</u>

The Company will endeavor to maintain continuous service but will not be liable for loss or damage caused by interruption or failure of service or delay in commencing service due to accident to or breakdown of plant, lines, or equipment, strike, riot, act of God, or causes reasonably beyond the Company’s control or due to shutdown for reasonable periods to make repairs to lines or equipment.

In like manner, should the Customer's premises be rendered wholly unfit for the continued operation of the Customer's plant or business, due to any of the causes mentioned above, the Customer's contract, if any, will thereupon be suspended until such time as the plant or premises will have been reconstructed, reconditioned, and reoccupied by the Customer for the purpose of his business.

13. INTERRUPTION OF SERVICE

The Company shall not be responsible in damages for any failure to supply electricity, or for interruption, or reversal of the supply, if such failure, interruption, or reversal is without willful default or negligence on its part, nor for interruptions, by under frequency relays or otherwise, to preserve the integrity of the Company's system or interconnected systems.

14. METERING

The electricity used will be measured by a meter or meters to be furnished and installed by the Company at its expense and bills will be calculated upon the registration of such meters. Meters include all measuring instruments. Meter installations will be made in accordance with the Company's service standards. Customer will provide a sufficient and proper space in a clean and safe place, accessible at all times and free from vibration, for the installation of Company's meters. Company will furnish all meter bases and/or metering enclosures to be installed by Customer on supply side of service equipment to be metered.

15. PROTECTION OF COMPANY'S PROPERTY AND ACCESS TO PREMISES

The Customer will protect the Company's property on the Customer's premises from loss or damage and will permit no one who is not an agent of the Company to remove or tamper with the Company's property.

The Company will have the right of access to the Customer's premises at all reasonable times for the purpose of installing, reading, inspecting, or repairing any meters or devices owned by Company or for the purpose of removing its property.

16. AGENTS CANNOT MODIFY AGREEMENT

No agent has power to amend, modify, or waive any of these Terms and Conditions, or to bind the Company by making any promises or representations not contained herein.

17. SUPERSEDE PREVIOUS TERMS AND CONDITIONS

These Terms and Conditions supersede all Terms and Conditions under which the Company has previously supplied electric service.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-2.1	Sheet 1 of 2
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Residential	
Part III. Rate Schedule No. 2		
Title: RESIDENTIAL SERVICE		

PSC File Mark Only

AVAILABILITY

This schedule is available to residential customers for all domestic uses in residences, individual family apartments, and private rooming houses.

Where a portion of a residential unit is used for non-residential purposes, the appropriate non-residential service schedule is applicable to all uses of electric service. However, this rate schedule may be applied to the residential portion of such use provided the Customer's wiring is so arranged that the use of electric service for residential purposes can be metered separately from the non-residential use.

NET MONTHLY RATE

Customer Charge:	$10.00~~7.75~~ Per Meter, plus
Kilowatt-hour Charge:	May through September Billing Cycles $0.0702~~0442~~ each for the first 1,500 kilowatt-hours $0.0919~~0534~~ each for all additional kilowatt-hours October through April Billing Cycles $0.0610~~0358~~ per kilowatt-hour

R-2 RS_02-01-2019

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Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

Multiple Dwelling: Where service is rendered through one meter to a multiple dwelling unit or apartment house, the amount of the Customer Charge will be multiplied by the number of single residence units served.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-3.1	Sheet 1 of 2
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Residential	
Part III. Rate Schedule No. 3		
Title: ELECTRIC HEATING APPLIANCE RESIDENTIAL SERVICE Closed to New Applications		PSC File Mark Only

AVAILABILITY

This schedule is available to residential customers for all domestic uses in residences, individual family apartments, and private rooming houses under one or both of the following conditions:

1. When a Customer regularly uses one or more Company-approved electric water heaters for all water heating requirements, notifies the Company, and has the installation verified by Company personnel, and/or,

2. When there is a permanently installed electric reverse cycle central system heat pump or a total of five kilowatts or more of permanently installed electric space heating devices which are in regular use for space heating purposes, and the Customer notifies the Company, and has the installation verified by Company personnel.

Where a portion of a residential unit is used for non-residential purposes, the appropriate non-residential service schedule is applicable to all uses of electric service. However, this rate schedule may be applied to the residential portion of such use provided the Customer's wiring is so arranged that the use of electric service for residential purposes can be metered separately from the non-residential use.

NET MONTHLY RATE

Customer Charge:	$10.00~~7.75~~ Per Meter, plus
Kilowatt-hour Charge:	May through September Billing Cycles $0.0702~~0442~~ each for the first 1,500 kilowatt-hours $0.0919~~0534~~ each for all additional kilowatt-hours
	October through April Billing Cycles $0.0610~~0358~~ each for the first 500 kilowatt-hours $0.0380~~0230~~ each for all additional kilowatt-hours

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ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. R-3.2 Sheet 2 of 2

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: Residential

Part III. Rate Schedule No. 3

Title: ELECTRIC HEATING APPLIANCE RESIDENTIAL SERVICE
Closed to New Applications

PSC File Mark Only

ADJUSTMENTS:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

Multiple Dwelling: Where service is rendered through one meter to a multiple dwelling unit or apartment house, the amount of the Customer Charge will be multiplied by the number of single residence units served.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original **Sheet No:** R-4.1 Sheet 1 of 1

Replacing: **Sheet No:**

Name of Company: SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric **Class of Service:** ~~Residential~~

Part III. ~~Rate Schedule No. 4~~

Title: RESERVED FOR FUTURE USE ~~RESIDENTIAL - RIDER TO RESIDENTIAL SERVICE FOR CONTROLLED SERVICE TO WATER HEATERS (closed to new installations)~~

PSC File Mark Only

~~This schedule has been removed from the tariff book.~~

Reserved for future use

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-5.1	Sheet 1 of 3
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 5		
Title: GENERAL SERVICE		PSC File Mark Only

AVAILABILITY

This rate schedule is available to all customers except multiple or individual dwellings or apartment houses, on an annual basis for secondary service for lighting, heating and power, or combination of lighting, heating and power where facilities of adequate capacity and suitable phase and voltage are available. Service will be supplied at one point of delivery through one meter. This schedule is available for Demand up to 50 kilowatts.

NET MONTHLY RATE

~~Customer Charge:~~	~~$8.60 Per Meter, plus~~ ~~$4.25 for each Kilowatt of Billing Demand in excess of 6 Kilowatts of Billing Demand~~
~~Kilowatt-hour Charge:~~	~~May through September Billing Cycles~~ ~~$0.0307 per kilowatt-hour~~ ~~October through April Billing Cycles~~ ~~$0.0257 per kilowatt-hour~~
~~**EFFECTIVE CYCLE 1, MAY 2011**~~	
Customer Charge:	$10.60~~8.60~~ Per Meter, plus $6.51~~4.20~~ for each Kilowatt of Billing Demand in excess of 6 Kilowatts of Billing Demand
Kilowatt-hour Charge:	May through September Billing Cycles $0.0456~~0307~~ per kilowatt-hour October through April Billing Cycles $0.0373~~0252~~ per kilowatt-hour

Determination of Kilowatts of Billing Demand: The Kilowatts of Billing Demand for each month will be the average kilowatt load used by the Customer during the 15-minute period of maximum use during the month. The Kilowatts of Billing Demand will be subject to the Power Factor Adjustment Clause.

Contract Minimum: When a contract minimum is applicable, the Customer's minimum monthly bill will not be less than the applicable charge for the contracted demand minimum plus the applicable Fuel and Tax Adjustments.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-5.3 Sheet 3 of 3	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 5		
Title: GENERAL SERVICE		PSC File Mark Only

Capacity Charge for Highly Fluctuating Loads: Should the Customer operate equipment with highly fluctuating, intermittent, or abnormal characteristics that make it necessary for the Company to install special facilities to serve the Customer or to prevent disturbances to the service to other Customers, an additional Distribution Function charge of $1.58~~00~~ per month per kilovolt-ampere (kVA) or fraction thereof of transformer capacity installed by the Company to serve the Customer will be added to the Customer's bill.

Power Factor Adjustment: The Company reserves the right to determine the power factor of the Customer's installation served hereunder. Should the average lagging power factor during the month be determined to be below 90%, the Customer's Kilowatts of Billing Demand will be adjusted by multiplying the Kilowatts of Billing Demand by 90% and dividing by the average lagging power factor.

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer’s bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-6.1	Sheet 1 of 4
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 6		
Title: LIGHTING AND POWER		PSC File Mark Only

AVAILABILITY

This rate schedule is available to all customers, except multiple or individual dwellings or apartment houses, on an annual basis for service for lighting, heating and power or combination of lighting, heating and power where facilities of adequate capacity and suitable phase and voltage are available. Service will be supplied at one point of delivery through one meter. This schedule is available for Billing Demands from 50 kilowatts to 10,000 kilowatts.

NET MONTHLY RATE

~~Secondary Service:~~

~~May through September Billing Cycles~~
~~$7.55 for each Kilowatt of Billing Demand in the month, but not less than $377.50~~

~~$0.0160 per kilowatt-hour~~

~~October through April Billing Cycles~~
~~$6.11 for each Kilowatt of Billing Demand in the month, but not less than $305.50~~

~~$0.0047 per kilowatt-hour~~

~~**EFFECTIVE CYCLE 1, MAY 2011 – SECONDARY SERVICE ONLY**~~

Secondary Service:

May through September Billing Cycles
$12.73~~7.55~~ for each Kilowatt of Billing Demand in the month, but not less than $636.50~~377.50~~

$0.0270~~0160~~ per kilowatt-hour

October through April Billing Cycles
$10.22~~6.10~~ for each Kilowatt of Billing Demand in the month, but not less than $511~~305~~.00

$0.0079~~0047~~ per kilowatt-hour

ARKANSAS PUBLIC SERVICE COMMISSION

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric | Class of Service: As Applicable

Part III. Rate Schedule No. 6

Title: LIGHTING AND POWER

PSC File Mark Only

Primary Service:

May through September Billing Cycles
$11.16~~6.80~~ for each Kilowatt of Billing Demand in the month, but not less than $558~~340~~.00

$0.02573~~01565~~ per kilowatt-hour

October through April Billing Cycles
$8.80~~5.35~~ for each Kilowatt of Billing Demand in the month, but not less than $440.00~~267.50~~

$0.0074~~0045~~ per kilowatt-hour

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-6.3 Sheet 3 of 4	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 6		
Title: LIGHTING AND POWER		PSC File Mark Only

Determination of Kilowatts of Billing Demand: The Kilowatts of Billing Demand for each month will be the average kilowatt load used by the Customer during the 15-minute period of maximum use during the month, but not less than 70% of the highest Kilowatts of Billing Demand established during the 11 preceding months. The Kilowatts of Billing Demand will be subject to the Power Factor Adjustment Clause.

Contract Minimum: When a contract minimum is applicable, the Customer's minimum monthly bill will not be less than the applicable charge for the contracted demand minimum plus the applicable Fuel and Tax Adjustments.

Capacity Charge for Highly Fluctuating Loads: Should the Customer operate equipment with highly fluctuating, intermittent, or abnormal characteristics that make it necessary for the Company to install special facilities to serve the Customer or to prevent disturbances to the service to other Customers, an additional Distribution Function charge of $1.58~~00~~ per month per kilovolt-ampere (kVA) or fraction thereof of transformer capacity installed by the Company to serve the Customer will be added to the Customer's bill.

Power Factor Adjustment: The Company reserves the right to determine the power factor of the Customer's installation served hereunder. Should the average lagging power factor during the month be determined to be below 90%, the Customer's Kilowatts of Billing Demand will be adjusted by multiplying the Kilowatts of Billing Demand by 90% and dividing by the average lagging power factor.

Primary Service: Applicable when electric service is provided at the Company's primary distribution voltage of 12.5 kV or higher and the Customer furnishes and maintains all necessary transformation equipment beyond this point.

APSC FILED Time: 2/28/2019 2:15:14 PM: Recvd 2/28/2019 2:14:10 PM: Docket 19-008-U-Doc. 39

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under Company's Standard Terms and Conditions

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ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-7.1	Sheet 1 of 3
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 7		
Title: LARGE LIGHTING AND POWER		PSC File Mark Only

AVAILABILITY

This rate schedule is available to all customers on an annual basis for service for lighting, heating and power or combination of lighting, heating and power where facilities of adequate capacity and suitable phase and voltage are available. Service will be supplied at one point of delivery though one meter. This schedule is available for Billing Demands of 10,000 kilowatts or greater.

NET MONTHLY RATE

~~Primary Service:~~	~~May through September Billing Cycles~~ ~~$68,000 for the first 10,000 kilowatts of Billing Demand or less in the month~~ ~~$6.80 each for all kilowatts in excess of 10,000 kilowatts in excess of 10,000 kilowatts of Billing Demand in the month~~ ~~$0.01565 per kilowatt-hour~~ ~~October through April Billing Cycles~~ ~~$53,500 for the first 10,000 Kilowatts of Billing Demand or less in the month~~ ~~$5.35 each for all kilowatts in excess of 10,000 Kilowatts of Billing Demand in the month~~ ~~$0.0045 per kilowatt-hour~~

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-7.2	Sheet 2 of 3
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 7		
Title: LARGE LIGHTING AND POWER		PSC File Mark Only

Transmission Service:

May through September Billing Cycles
$88,100~~52,600~~ for the first 10,000 Kilowatts of Billing Demand or less in the month

$8.81~~5.26~~ each for all kilowatts in excess of 10,000 Kilowatts of Billing Demand in the month

$0.0223~~0133~~ per kilowatt-hour

October through April Billing Cycles
$66,500~~39,700~~ for the first 10,000 Kilowatts of Billing Demand or less in the month

$6.65~~3.97~~ each for all kilowatts in excess of 10,000 Kilowatts of Billing Demand in the month

$0.0060~~0036~~ per kilowatt-hour

Determination of Kilowatts of Billing Demand: The Kilowatts of Billing Demand for each month will be the average kilowatt load used by the Customer during the 15-minute period of maximum use during the month but not less than 80% of the highest Kilowatts of Billing Demand established during the 11 preceding months. The Kilowatts of Billing Demand will be subject to the Power Factor Adjustment Clause.

Contract Minimum: When a contract minimum is applicable, the Customer's minimum monthly bill will not be less than the applicable charge for the contracted demand minimum plus the applicable Fuel and Tax Adjustments.

Capacity Charge for Highly Fluctuating Loads: Should the Customer operate equipment with highly fluctuating, intermittent, or abnormal characteristics that make it necessary for the Company to install special facilities to serve the Customer or to prevent disturbances to the service to other Customers, an additional Distribution Function charge of $1.58~~00~~ per month per kilovolt-

ampere (kVA) or fraction thereof of transformer capacity installed by the Company to serve the Customer will be added to the Customer's bill.

Power Factor Adjustment: The Company reserves the right to determine the power factor of the Customer's installation served hereunder. Should the power factor at the time of establishment of any 15-minute period of maximum use during the month be determined to be below 90%, the Customer's Kilowatts of Billing Demand will be adjusted by multiplying the Kilowatts of Billing Demand by 90% and dividing the result by the actual power factor at the time of maximum use.

Transmission Service: Applicable when electric service is provided at the Company's available transmission voltages of 69 kV or higher and the Customer furnishes and maintains all necessary transformation equipment beyond this point.

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer’s bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original | Sheet No. R-8.1 | Sheet 1 of 5

Replacing: | Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric | Class of Service: Industrial - Time of Use

Part III. Rate Schedule No. 8

Title: LIGHTING AND POWER – TIME OF USE

PSC File Mark Only

AVAILABILITY

This rate schedule is available to Industrial customers on an annual basis having loads of 500 Kilowatts of maximum demand or greater. Service will be provided at one point of delivery through one meter where facilities of adequate capacity and suitable phase and voltage are available.

NET MONTHLY RATE

Secondary Service:

On-Peak

$21.33~~11.65~~ for each Kilowatt of On-Peak Billing Demand in the month but not less than $1,066.50~~582.50~~

$0.1039~~0556~~ per kilowatt-hour

Off-Peak

$8.82~~3.25~~ for each Kilowatt of Off-Peak Billing Demand in the month, but not less than $441.00~~162.50~~

$0.0161~~0070~~ per kilowatt-hour

Primary Service:

On-Peak

$16.52~~11.00~~ for each Kilowatt of On-Peak Billing Demand in the month, but not less than $826~~550~~.00

$0.1005~~0554~~ per kilowatt-hour

Off-Peak

$6.43~~2.65~~ for each Kilowatt of Off-Peak Billing Demand in the month, but not less than $321.50~~132.50~~

$0.0142~~0068~~ per kilowatt-hour

Determination of Kilowatts of Billing Demand: Billing Demands will be separately maintained and applied for the On-Peak and Off-Peak periods. Billing Demands shall be calculated as follows:

On-Peak: The Kilowatts of On-Peak Billing Demand for each month in which On-Peak period rates are applicable shall be the average kilowatt load used by the customer during the 15-minute period of maximum use during that month's On-Peak period, but not less than 70% of the highest Kilowatts of Billing Demand established during the On-Peak period during the 11 preceding months. The Kilowatts of On-Peak Billing Demand shall be subject to the Power Factor Adjustment Clause.

Off-Peak: The Kilowatts of Off-Peak Billing Demand for each month shall be the average kilowatt load used by the Customer during the 15-minute period of maximum use during the Off-Peak period of that month, but not less than 70% of the highest Kilowatts of Billing Demand established during either the On-Peak or Off-Peak period during the 11 preceding months. The Kilowatts of Off-Peak Billing Demand shall be subject to the Power Factor Adjustment Clause.

Contract Minimum: The customer’s minimum bill shall not be less than the applicable charge for the contracted demand minimum plus the applicable Fuel and Tax Adjustments and in no event shall the contract demand minimum be less than 500 kilowatts.

Definition of Rating Periods:

On-Peak: The On-Peak hours shall be the hours from 1:01 p.m. through 7:00 p.m. during weekdays, excluding national holidays, during the months of July, August and September.

Off-Peak: The Off-Peak hours shall be all hours other than the On-Peak hours.

Capacity Charge for Highly Fluctuating Loads: Should the Customer operate equipment with highly fluctuating, intermittent, or abnormal characteristics that make it necessary for the Company to install special facilities to serve the Customer or to prevent disturbances to the service to other Customers, an additional Distribution Function charge of $1.58~~00~~ per month per kilovolt-ampere (kVA) or fraction thereof of transformer capacity installed by the Company to serve the Customer will be added to the Customer's bill.

Power Factor Adjustment: The Company reserves the right to determine the power factor of the Customer's installation served hereunder. Should the average lagging power factor during the month be determined to be below 90%, the Customer's Kilowatts of Billing Demand in each rating period will be adjusted by multiplying the Kilowatts of Billing Demand in each rating period by 90% and dividing by the average lagging power factor.

Primary Service: Applicable when electric service is provided at the Company's primary distribution voltage of 12.5 kV or higher and the Customer furnishes and maintains all necessary transformation equipment beyond this point.

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per Kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-9.1	Sheet 1 of 6
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Pulp & Paper Mill	
Part III. Rate Schedule No. 9		
Title: PULP AND PAPER MILL SERVICE		

PSC File Mark Only

AVAILABILITY

This rate schedule is available to pulp and paper mills on an annual basis where facilities of adequate capacity and suitable phase and voltage are available. Service will be supplied at one point of delivery through one meter.

PULP AND PAPER MILL RATE

The Company shall render a bill and the Customer shall pay for electric service supplied each month an amount to be determined in the following manner:

$154,200~~105,000~~	Each month during the life of the contract for which the Customer will be allowed the use of up to 20,000 Kilowatts of Billing Demand determined as hereinafter provided, plus
$7.71~~5.25~~	Per Kilowatt of Billing Demand each month for the maximum number of Kilowatts of Billing Demand in any one month of the 12-month period ending with the current month that are in excess of 20,000 Kilowatts of Billing Demand, plus
$0.0103~~0070~~	Per kilowatt-hour for all kilowatt-hours supplied during the month

Determination of Kilowatts of Billing Demand: The Kilowatts of Billing Demand will be measured and will be the kilowatt load supplied during the 15-minute period of maximum use in the 12-month period ending with the current month, but never less than 20,000 kilowatts.

Power Factor Adjustment: In the event the power factor at the time of establishment of any 15-minute period of maximum use during the month is less than 90%, the Kilowatts of Billing Demand shall be adjusted by multiplying the Kilowatts of Billing Demand by 90% and dividing the result by the actual power factor at the time of said maximum use, and the result so obtained shall be Kilowatts of Billing Demand for the month, but never less than the maximum number of Kilowatts of Billing Demand in the 12-month period ending with the current month and, in any event, not less than 20,000 kilowatts.

Minimum Monthly Bill: The minimum monthly bill will be the maximum Kilowatts of Billing Demand charge during the 12-month period ending with the current month, but never less than the charge of $154,200~~105,000~~.00 for the first 20,000 Kilowatts of Billing Demand or less, and plus or minus the Fuel Adjustment charge plus the Tax Adjustment charge.

Annual Guarantee: It is mutually understood and agreed that in order for Company to be equitably compensated for permitting Customer to operate its plant generators in parallel with Company system the Customer will take or pay for, each year ending on October 31, a minimum of 2,000 hours times the maximum number of Kilowatts of Billing Demand previously determined, but not less than 40,000,000 kilowatt-hours per year.

Kilowatt-hours used during periods of turbine-generator overhaul, maintenance or emergency shall not be included in the Annual Guarantee.

Conjunctive Rate Provisions: When the Pulp and Paper Mill rate is used in conjunction with the Supplementary, Backup, Maintenance, and As-Available Standby Power Service rate, the Power Factor Adjustment and the following provisions for turbine-generator overhaul, emergency power, and maintenance power will not apply.

Turbine-Generator Overhaul: It is recognized that it will be necessary for the integrated operations of the turbine-generators of Customer and power service of the Company, that scheduled overhaul periods on the equipment of the Customer must be fitted into the similar schedules of the Company. During periods of agreed overhaul the Kilowatts of Billing Demand shall be based on actual kilowatts during such overhaul period but in no event less than maximum Kilowatts of Billing Demand previously established under normal operations. The Kilowatts of Billing Demand established during overhaul period will not be used to determine the maximum kilowatt load previously established.

Emergency Power: The Company recognizes that actual emergencies can occur to Customer's generating facilities and that Customer may desire assistance in supplying such loss of generating capability not to exceed 30 days for any one emergency.

The Company will, to the extent of facilities then available, make every reasonable effort to supply Customer's emergency. Customer agrees to correct its emergency conditions as soon as reasonably possible. An authorized representative of the Customer shall notify Company's system operations center's authorized representative at time of the beginning of the emergency, the cause and the expected duration thereof. The Customer's representative will also notify Company at the time the emergency ends. Such notices shall be confirmed by letter containing the same information to the authorized representative within 24 hours of the start and end of the emergency.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-9.4	Sheet 4 of 6
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Pulp & Paper Mill	
Part III. Rate Schedule No. 9		
Title: PULP AND PAPER MILL SERVICE		

PSC File Mark Only

The Customer shall pay the Company for all emergency load and energy supplied on the following basis:

$9.30~~6.66~~	per Kilowatt of Billing Demand in excess of the Determination of Kilowatts of Billing Demand under normal firm load conditions or a minimum of 20,000 kilowatts, plus
$0.02230~~0152~~	per kilowatt-hour plus Fuel Adjustment charge or 110% of Company's highest kilowatt-hour cost either purchased or generated during the time of the emergency, whichever is greater. The kilowatt-hours will be the sum of the kilowatt-hours determined by multiplying the Maximum demand in each hour of the emergency that is in excess of the determination of Kilowatts of Billing Demand under normal firm load conditions times one hour.

Maintenance Power: To enable the Customer to repair and maintain the operating efficiency of its facilities, the Customer may purchase additional power referred to as "Maintenance Power" from the Company. Maintenance Power shall be arranged in advance by telephone

requests to the Company's system operation center. Such Maintenance Power will be supplied, provided the Company is reasonably certain that a system peak will not be created during this period and providing the Company in its judgment has adequate capacity in its own system to supply the requested demand. Maintenance Power requests will be for a limited period of time as specified by Company. Maintenance Power will be extremely limited or unavailable during the months of June, July, August and September. Company reserves the right to terminate Customer's purchase of Maintenance Power due to changes within this system with one-hour notice to Customer. Maintenance Power will be provided only during periods when the Customer is receiving firm power from the Company. The Customer will pay for such maintenance power on whichever of the following basis is applicable:

Maintenance Power - Used only from 11:00 p.m. on Fridays until 7:00 a.m. on Mondays and from 12:01 a.m. on holidays to 7:00 a.m. the following morning.

$3.85~~2.62~~	per Kilowatt of Billing Demand in excess of the Determination of Kilowatts of Billing Demand under normal firm load conditions or a minimum of 20,000 kilowatts, plus
	the normal charges per kilowatt-hour as provided in the rate schedule.

ARKANSAS PUBLIC SERVICE COMMISSION

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: Pulp & Paper Mill

Part III. Rate Schedule No. 9

Title: PULP AND PAPER MILL SERVICE

PSC File Mark Only

Maintenance Power - Used at any time in addition to or including 11:00 p.m. on Fridays until 7:00 a.m. on Mondays and from 12:01 a.m. on holidays to 7:00 a.m. the following morning.

$7.68~~5.23~~ per Kilowatt of Billing Demand in excess of the Determination of Kilowatts of Billing Demand under normal firm load conditions or a minimum of 20,000 kilowatts, plus

the normal charges per kilowatt-hour as provided in the rate schedule.

The Kilowatts of Billing Demand created during an agreed to use of Maintenance Power in excess of the Determination of Kilowatts of Billing Demand under normal firm load conditions will not be used to determine the maximum kilowatt load previously established.

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

AVAILABILITY

This schedule is available on an annual basis for lighting and power to municipal installations in communities where the Company has a franchise for the generation, distribution, and sale of electricity, together with a standard contract for the operation of a street lighting system when the Customer purchases its entire lighting and power requirements from the Company.

NET MONTHLY RATE

~~Customer Charge:~~ ~~$5.35 per meter, plus~~

~~Kilowatt-hour Charge:~~ ~~May through September Billing Cycles~~
~~$0.0405 per kilowatt-hour~~

~~October through April Billing Cycles~~
~~$0.0360 per kilowatt-hour~~

~~EFFECTIVE CYCLE 1, MAY 2011~~

Customer Charge: $7.36~~5.35~~ per meter, plus

Kilowatt-hour Charge: May through September Billing Cycles
$0.0557~~0405~~ per kilowatt-hour

October through April Billing Cycles
$0.0494~~0359~~ per kilowatt-hour

Minimum Monthly Bill: The Minimum Monthly Bill will be $1.76~~28~~ per Kilowatt of Maximum Demand established during the 11 preceding months, but not less than $7.36~~5.35~~. For Minimum Monthly Bills rated in horsepower, each horsepower will be considered equal to 3/4 kilowatt.

Determination of Kilowatts of Maximum Demand: The Kilowatts of Maximum Demand for each month will be the average kilowatt load used by the Customer during the 15-minute

period of maximum use during the month. The Kilowatts of Maximum Demand will be subject to the Power Factor Adjustment Clause.

<u>Contract Minimum</u>: When a contract minimum is applicable, the Customer's minimum monthly bill will not be less than the applicable charge for the contracted demand minimum plus the applicable Fuel and Tax Adjustments.

ARKANSAS PUBLIC SERVICE COMMISSION

Capacity Charge for Highly Fluctuating Loads: Should the Customer operate equipment with highly fluctuating, intermittent, or abnormal characteristics that make it necessary for the Company to install special facilities to serve the Customer or to prevent disturbances to the service to other Customers, an additional Distribution Function charge of $1.58~~00~~ per month per kilovolt-ampere (kVA) or fraction thereof of transformer capacity installed by the Company to serve the Customer will be added to the Customer's bill.

Power Factor Adjustment: The Company reserves the right to determine the power factor of the Customer's installation served hereunder. Should the average lagging power factor during the month be determined to be below 90%, the Customer's Kilowatts of Maximum Demand will be adjusted by multiplying the Kilowatts of Maximum Demand by 90% and dividing by the average lagging power factor.

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer’s bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under Company's Standard Terms and Conditions

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-11.1 Sheet 1 of 3	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Municipal	
Part III. Rate Schedule No. 11		
Title: MUNICIPAL PUMPING		PSC File Mark Only

AVAILABILITY

This schedule is available on an annual basis for all municipal water and sewerage pumping, with the exception of standby, breakdown, or auxiliary service, in communities in which the Company has a franchise for the generation, distribution, and sale of electricity, together with a standard contract for the generation, distribution, and sale of electricity, together with a standard contract for the operation of a street lighting system, when the Customer purchases its entire lighting and power requirements from the Company.

CHARACTER OF SERVICE

Power and energy supplied under this schedule will be at either primary or secondary voltage, depending on the Customer's requirements and the availability of such voltage from the Company's established primary or secondary circuits.

MEASUREMENT OF POWER AND ENERGY

Power and energy supplied hereunder will be measured by metering installations at each point of delivery and the kilowatt-hours registered at all points of delivery will be combined to determine the total kilowatt-hours to be used in computing the Customer's monthly bill under this schedule.

NET MONTHLY RATE

Customer Charge:	$7.36~~5.35~~ per meter, plus
Kilowatt-hour Charge:	May through September Billing Cycles $0.0492~~0358~~ per kilowatt-hour
	October through April Billing Cycles $0.0426~~0310~~ per kilowatt-hour

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-11.2 Sheet 2 of 3	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Municipal	
Part III. Rate Schedule No. 11		
Title: MUNICIPAL PUMPING		PSC File Mark Only

Minimum Monthly Bill: The Minimum Monthly Bill will be $1.76~~28~~ per Kilowatt of Maximum Demand established during the 11 preceding months, but not less than $7.36~~5.35~~. For Minimum Monthly Bills rated in horsepower, each horsepower will be considered equal to 3/4 kilowatt.

Determination of Kilowatts of Maximum Demand: The Kilowatts of Maximum Demand for each month will be the average kilowatt load used by the Customer during the 15-minute period of maximum use during the month. The Kilowatts of Maximum Demand will be subject to the Power Factor Adjustment Clause.

Contract Minimum: When a contract minimum is applicable, the Customer's minimum monthly bill will not be less than the applicable charge for the contracted demand minimum plus the applicable Fuel and Tax Adjustments.

Capacity Charge for Highly Fluctuating Loads: Should the Customer operate equipment with highly fluctuating, intermittent, or abnormal characteristics that make it necessary for the Company to install special facilities to serve the Customer or to prevent disturbances to the service to other Customers, an additional Distribution Function charge of $1.58~~00~~ per month per kilovolt-ampere (kVA) or fraction thereof of transformer capacity installed by the Company to serve the Customer will be added to the Customer's bill.

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Power Factor Adjustment: The Company reserves the right to determine the power factor of the Customer's installation served hereunder. Should the average lagging power factor during the month be determined to be below 90%, the Customer's Kilowatts of Maximum Demand will be adjusted by multiplying the Kilowatts of Maximum Demand by 90% and dividing by the average lagging power factor.

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer’s bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-12.1	Sheet 1 of 2
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Municipal	
Part III. Rate Schedule No. 12		
Title: MUNICIPAL STREET LIGHTING (no new installations allowed)		PSC File Mark Only

AVAILABILITY

This schedule is available for municipal street lighting purposes in any community in which the Company has a franchise for the generation, distribution and sale of electricity, and where the Company furnishes, installs, owns, operates and maintains the facilities. No new installations will be allowed on this schedule. As existing mercury vapor fixtures and/or ballasts need to be replaced on or after April 1, 2007, the Customer will have the option to transfer to another open tariff offering.

TYPE OF SERVICE

The lights shall burn every night from dusk to dawn.

NET MONTHLY RATE

Rate Modifier	Description	Rate Per Lamp	Company Will Invest Up to But Not to Exceed – Per Lamp
	Mercury Vapor		
031	75 Watt	$3.76~~5.98~~	$100
032	100 Watt	$3.82~~6.08~~	$105
033	175 Watt	$3.92~~6.23~~	$110
028	400 Watt	$4.26~~6.78~~	$165 (1)
035	400 Watt	$4.67~~7.43~~	$165 (1)
036*	400 Watt	$4.67~~7.43~~	$165 (1)
037	400 Watt	$6.98~~11.10~~	$250 (2)
039	400 Watt	$7.37~~11.73~~	$285 (1)
041	400 Watt	$12.47~~19.83~~	$450 (2)

*Series
(1) On wood pole
(2) On steel pole

ARKANSAS PUBLIC SERVICE COMMISSION

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original | Sheet No. R-13.1 | Sheet 1 of 3

Replacing: | Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric | Class of Service: Municipal

Part III. Rate Schedule No. 13

Title: MUNICIPAL STREET LIGHTING & PARKWAY LIGHTNG (no new installations allowed)

PSC File Mark Only

AVAILABILITY

This schedule is available for municipal street and parkway lighting systems installed in any community in which the Company has a franchise for the generation, distribution and sale of electricity. This schedule is applicable to existing facilities only with no new installations allowed. As existing mercury vapor fixtures and/or ballasts need to be replaced on or after April 1, 2007, the Customer will have the option to transfer to another open tariff offering. As existing metal halide or high pressure sodium facilities need to be replaced and existing inventory is depleted, the Customer will have the option to transfer to another open tariff offering.

TYPE OF SERVICE

The Company will furnish, install, own, operate, maintain, clean and repair the street and parkway lighting system of design as mutually approved by the Customer and the Company. The lamps will be controlled to burn from dusk to dawn. The Customer agrees to provide, at no cost to the Company, all required right-of-way together with tree trimming permits for installation of the system and any permit necessary to allow Company the right to use highway, parkway and street right-of-way for maintenance of the system.

NET MONTHLY RATE

Rate Modifier	Description	kWh	Monthly Rate Per Lamp
	Mercury Vapor		
284	100 Watt	42	$2.75~~4.38~~
285	175 Watt	68	$2.78~~4.43~~
287	400 Watt	155	$3.57~~5.68~~
288	1000 Watt	364	$5.34~~8.50~~

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ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. R-13.2 Sheet 2 of 3

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: Municipal

Part III. Rate Schedule No. 13

Title: MUNICIPAL STREET LIGHTING & PARKWAY LIGHTNG (no new installations allowed)

PSC File Mark Only

Rate Modifier	Description	kWh	Monthly Rate Per Lamp
	Metal Halide		
282	400 Watt	156	$4.09~~6.50~~
283	1000 Watt	373	$6.26~~9.95~~
	High Pressure Sodium		
295	70 Watt	35	$2.92~~4.65~~
290	100 Watt	49	$2.94~~4.68~~
294	150 Watt	59	$2.94~~4.68~~
291	250 Watt	105	$3.39~~5.40~~
292	400 Watt	165	$3.76~~5.98~~
293	1000 Watt	388	$6.23~~9.91~~

Facilities Charge:

There will be a charge each month equal to:

1.46~~75~~% times the amount of the Company investment in the system to compensate the Company for its investment and maintenance thereon, and/or

0.69~~57~~% times the amount of the Customer contribution in the system to compensate the Company for maintenance thereon.

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Adjustments**:**

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-14.1 Sheet 1 of 2	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 14		
Title: MUNICIPAL STREET LIGHITNG (no new installations allowed)		PSC File Mark Only

Rate for 100 watt mercury vapor luminaries mounted on ornamental standards supplied by underground circuits.

ELECTRIC SERVICE LINE EXTENSION AGREEMENT SIGNED WITH
James R. Hale, Developer, Virginia Hills Addition
and
Oak Manor Developing Company

Rate Modifier	Description	kWh	Total
030*	Mercury Vapor 100 Watt	42	$4.89~~7.78~~

This installation was made prior to promulgation of our standard rate for Mercury Vapor Lamps. Under the Street Lighting Schedule this installation is considered as "Ornamental Standards" with a Customer contribution for all investment in excess of $220 per lamp. Billing is to the City of Fayetteville, Arkansas.

* Note: This rate is applicable to the presently installed system only with no new installations allowed. As existing mercury vapor fixtures and/or ballasts need to be replaced on or after April 1, 2007, the Customer will have the option to transfer to another open tariff offering.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-14.2 Sheet 2 of 2	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 14		
Title: MUNICIPAL STREET LIGHITNG (no new installations allowed)		PSC File Mark Only

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-15.1	Sheet 1 of 3
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 15		
Title: MUNICIPAL STREET & PARKWAY LIGHTING		PSC File Mark Only

AVAILABILITY

No new mercury vapor installations will be allowed on this schedule on or after April 1, 2007. As existing mercury vapor fixtures and/or ballasts need to be replaced on or after April 1, 2007, the Customer will have the option to transfer to another open tariff offering.

This schedule is available for municipal street and parkway lighting systems installed in any community in which the Company has a franchise for the generation, distribution, and sale of electricity.

TYPE OF SERVICE

The Company will furnish, install, own, operate, maintain, clean and repair the street and parkway lighting system of design as mutually approved by the Customer and the Company. The lamps will be controlled to burn from dusk to dawn. The Customer agrees to provide, at no cost to the Company, all required right-of-way together with tree trimming permits for installation of the system and any permit necessary to allow Company the right to use highway, parkway and street right-of-way for maintenance of the system.

NET MONTHLY RATE

Rate Modifier	Description	kWh	Monthly Rate Per Lamp
	Mercury Vapor		
508	175 Watt	68	$3.92~~6.23~~
509	400 Watt	155	$4.67~~7.43~~
	Metal Halide		
510	400 Watt	156	$4.09~~6.50~~
511	1000 Watt	373	$6.26~~9.95~~

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. R-15.2 Sheet 2 of 3

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: As Applicable

Part III. Rate Schedule No. 15

Title: MUNICIPAL STREET & PARKWAY LIGHTING

PSC File Mark Only

Rate Modifier	Description	kWh	Monthly Rate Per Lamp
	High Pressure Sodium		
512	100 Watt	49	$2.94~~4.68~~
513	250 Watt	105	$3.39~~5.40~~
514	400 Watt	165	$3.76~~5.98~~
515	1000 Watt	388	$6.23~~9.91~~
	Light Emitting Diode		
LED 01	0-100 Watts - Less than 10,000 Lumens	20	$3.68
LED 02	101-250 Watts – 10,000-25000 Lumens	56	$5.54
LED 03	Over 250 Watts – over 25,000 Lumens	100	$9.41

Facilities Charge:

There will be a charge each month equal to:

1.46~~43~~% times the amount of the Company investment in the system to compensate the Company for its investment and maintenance thereon, and/or

0.69~~60~~% times the amount of the Customer contribution in the system to compensate the Company for maintenance thereon.

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

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ARKANSAS PUBLIC SERVICE COMMISSION

PSC File Mark Only

REPLACEMENT, REMOVAL, OR DISCONNECT

When a customer requests that the Company replace an existing non-LED lighting system with an LED lighting system the customer may be required to pay to the Company a one-time Conversion Fee of $95.

When a customer requests that the Company disconnect or remove an existing LED lighting system the customer may be required to pay to the Company a one-time Removal Fee of $145.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. R-16.1 Sheet 1 of 2

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: As Applicable

Part III. Rate Schedule No. 16

Title: PUBLIC STREET & HIGHWAY LIGHTING - ENERGY ONLY (closed to new additions)

PSC File Mark Only

AVAILABILITY

This schedule is available for electric energy used in operation of public highway lighting systems at any point on the Company's interconnected system where secondary voltage service is available. This rate is applicable to existing luminaires only with no new additions allowed.

TYPE OF SERVICE

The Company will make available single phase, secondary voltage electric service from dusk to dawn at Customer points of service located adjacent to Company lines of adequate capacity and suitable voltage.

NET MONTHLY RATE

Rate Modifier	Description	kWh	Monthly Rate Per Lamp
	Mercury Vapor		
255	175 Watt	68	$2.84~~3.75~~
251	400 Watt	155	$4.05~~5.36~~
253	1000 Watt	364	$4.70~~6.21~~

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. R-16.2 Sheet 2 of 2

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: As Applicable

Part III. Rate Schedule No. 16

Title: PUBLIC STREET & HIGHWAY LIGHTING - ENERGY ONLY (closed to new additions)

PSC File Mark Only

Rate Modifier	Description	kWh	Rate Per Lamp Per Month
	Metal Halide		
256	400 Watt	156	$4.07~~5.38~~
257	1,000 Watt	373	$7.09~~9.38~~
	High Pressure Sodium		
258	70 Watt	35	$2.38~~3.15~~
259	100 Watt	49	$2.57~~3.40~~
261	250 Watt	105	$3.36~~4.44~~
262	400 Watt	165	$4.19~~5.54~~
263	1000 Watt	388	$7.30~~9.65~~.

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

THIS SPACE FOR PSC USE ONLY

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. R-17.1 Sheet 1 of 3

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: As Applicable

Part III. Rate Schedule No. 17

Title: PUBLIC STREET AND HIGHWAY LIGHTING
(closed to new additions)

PSC File Mark Only

AVAILABILITY

This schedule is available for electric service used in the operation of publicly-owned highway lighting systems utilizing luminaries mounted at heights not exceeding forty (40) feet above ground level and where the Company has no investment in facilities beyond the delivery point of service. This rate is applicable to existing luminaires only with no new additions allowed.

TYPE OF SERVICE

The Company will make available single phase, secondary voltage electric service from dusk to dawn at Customer points of service adjacent to Company lines of adequate capacity and suitable voltage.

The Customer will own, install, operate, and maintain its highway lighting system from the point of service connection with the Company lines. The Company will be responsible for relamping and will replace glassware to be furnished by Customer.

The Customer will provide the Company, at no cost to the Company, any permit necessary to allow the Company the right to use highway right-of-way for maintenance of the system.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-17.2 Sheet 2 of 3	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 17		
Title: PUBLIC STREET AND HIGHWAY LIGHTING (closed to new additions)		PSC File Mark Only

NET MONTHLY RATE

Rate Modifier	Description	kWh	Rate Per Lamp Per Month
	Mercury Vapor		
051	175 Watt	68	$3.02~~3.99~~
074	400 Watt	155	$4.46~~5.90~~
	Metal Halide		
052	400 Watt	156	$4.48~~5.93~~
053	1000 Watt	373	$7.25~~9.59~~
	High Pressure Sodium		
055	100 Watt	49	$2.71~~3.58~~
057	250 Watt	105	$3.64~~4.81~~
058	400 Watt	165	$4.39~~5.80~~
059	1000 Watt	388	$7.46~~9.87~~

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

ARKANSAS PUBLIC SERVICE COMMISSION

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. R-18.1 Sheet 1 of 2

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: As Applicable

Part III. Rate Schedule No. 18

Title: PUBLIC STREET AND HIGHWAY LIGHTING –ENERGY ONLY

PSC File Mark Only

AVAILABILITY

This schedule is available for electric energy used in operation of public highway lighting systems at any point on the Company's interconnected system where secondary voltage service is available.

TYPE OF SERVICE

The Company will make available single phase, secondary voltage electric service from dusk to dawn at Customer points of service located adjacent to Company lines of adequate capacity and suitable voltage.

NET MONTHLY RATE

Rate Modifier	Description	kWh	Rate Per Lamp Per Month
	Mercury Vapor		
265	175 Watt	68	$2.84~~3.75~~
266	400 Watt	155	$4.05~~5.36~~
	Metal Halide		
267	400 Watt	156	$4.07~~5.38~~
268	1000 Watt	373	$7.09~~9.38~~
	High Pressure Sodium		
269	100 Watt	49	$2.57~~3.40~~
270	250 Watt	105	$3.36~~4.44~~
271	400 Watt	165	$4.19~~5.54~~
272	1000 Watt	388	$7.30~~9.65~~

THIS SPACE FOR PSC USE ONLY

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-18.2	Sheet 2 of 2
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 18		
Title: PUBLIC STREET AND HIGHWAY LIGHTING –ENERGY ONLY		

PSC File Mark Only

Net Monthly Rate For Units Not Listed Above:
The Net Monthly Rate for lighting units not listed above will be calculated by the Company using the following formula:

Monthly kWh used by the lighting unit X $0.036050~~0266~~ = Net Monthly Rate rounded to the nearest $0.01, but not less than $1.00.

Where: Monthly kWh used by the lighting unit = ((Input watts rounded to the nearest whole number X 4,000 hours) / 1,000) / 12, rounded to the nearest whole number.

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-19.1 Sheet 1 of 2	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 19		
Title: PUBLIC STREET AND HIGHWAY LIGHTING		PSC File Mark Only

AVAILABILITY

This schedule is available for electric service used in the operation of publicly-owned highway lighting systems utilizing luminaries mounted at heights not exceeding forty (40) feet above ground level and where the Company has no investment in facilities beyond the delivery point of service.

TYPE OF SERVICE

The Company will make available single phase, secondary voltage electric service from dusk to dawn at Customer points of service adjacent to Company lines of adequate capacity and suitable voltage.

The Customer will own, install, operate, and maintain its highway lighting system from the point of service connection with the Company lines. The Company will be responsible for relamping and will replace glassware to be furnished by Customer.

The Customer will provide the Company, at no cost to the Company, any permit necessary to allow the Company the right to use highway right-of-way for maintenance of the system.

NET MONTHLY RATE

Rate Modifier	Description	kWh	Rate Per Lamp Per Month
	Mercury Vapor		
500	175 Watt	68	$3.02~~3.99~~
501	400 Watt	155	$4.46~~5.90~~
	Metal Halide		
502	400 Watt	156	$4.48~~5.93~~
503	1000 Watt	373	$7.25~~9.59~~
	High Pressure Sodium		
504	100 Watt	49	$2.71~~3.58~~
505	250 Watt	105	$3.64~~4.81~~
506	400 Watt	165	$4.39~~5.80~~
507	1000 Watt	388	$7.46~~9.87~~

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-19.2 Sheet 2 of 2	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 19		
Title: PUBLIC STREET AND HIGHWAY LIGHTING		PSC File Mark Only

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

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ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-20.1	Sheet 1 of 3
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Lighting	
Part III. Rate Schedule No. 20		
Title: PRIVATE LIGHTING (no new installations allowed)		PSC File Mark Only

AVAILABILITY

This schedule is available for existing private lighting systems only with no new installations allowed. As existing mercury vapor fixtures and/or ballasts need to be replaced on or after April 1, 2007, the Customer will have the option to transfer to another open tariff offering.

TYPE OF SERVICE

The Company will furnish, install, own, operate, and maintain complete luminaire units of approved design with an automatic control device for lights to burn from dusk to dawn for an agreed upon term of years to continue thereafter in automatically recurring yearly periods unless and until terminated at the end of any yearly period by 30 days prior notice from either party to the other.

The Customer agrees to provide all required right-of-way together with tree trimming permits and to protect the Company's equipment from damage.

The Company shall have the right to build pole line and install equipment upon the Customer's property and shall have access to the Customer's premises for any other purpose necessary for the performance of this service. The facilities installed by the Company will remain the property of the Company and may be removed by Company upon discontinuance of service.

The Company will exercise reasonable diligence at all times to furnish Customer service as contracted for, but will not be liable in damages for any interruption, deficiency or failure of service. The Company reserves the right to interrupt the service when such interruption is necessary for repairs to its lines or equipment.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-20.2	Sheet 2 of 3
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Lighting	
Part III. Rate Schedule No. 20		
Title: PRIVATE LIGHTING (no new installations allowed)		PSC File Mark Only

NET MONTHLY RATE

Installed on existing Company owned poles and connected to existing Company owned overhead lines of adequate capacity and suitable voltage.

Rate Modifier	Description	kWh	Monthly Rate Per Lamp
	~~**Incandescent**~~		
~~300*~~	~~2500 Lumen~~	~~63~~	~~$14.26~~
	Mercury Vapor		
302*	8000 Lumen	68	$3.54~~5.85~~
303**	8000 Lumen	68	$8.25~~13.63~~

*On existing pole
**With Special Facilities

Special Facilities: The Company will extend its secondary conductor one span not to exceed 125 feet in length and/or install one 30 foot wood pole, including guy and anchor where needed, for support of such luminaire. Extension of special facilities will be limited to one span and/or one pole for each luminaire.

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-21.1	Sheet 1 of 3
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Lighting	
Part III. Rate Schedule No. 21		
Title: AREA LIGHTING (no new installations allowed)		PSC File Mark Only

AVAILABILITY

This rate is available to customers requesting outdoor area lighting service for apartment projects, subdivisions, mobile home parks, parking lots, parks and grounds around buildings to be served from Company electric supply lines of adequate capacity and suitable voltage available, and where all the Customer's electricity requirements were purchased from the Company. This rate is applicable to existing installations only, with no new installations allowed. As existing mercury vapor fixtures and/or ballasts need to be replaced on or after April 1, 2007, the Customer will have the option to transfer to another open tariff offering. As existing metal halide or high pressure sodium facilities need to be replaced and existing inventory is depleted, the Customer will have the option to transfer to another open tariff offering.

TYPE OF SERVICE

The Company will furnish, install, own, operate, and maintain a complete area lighting system of design and installation approved by the Company. The lights will be controlled to burn from dusk to dawn.

NET MONTHLY RATE

The Customer agrees to pay for service at the following rate:

Rate Modifier	Description	kWh	Monthly Rate Per Lamp
	Mercury Vapor		
322	100 Watt	42	$6.14~~10.14~~
323	175 Watt	68	$6.19~~10.23~~
324	250 Watt	98	$6.42~~10.61~~
325	400 Watt	155	$6.45~~10.65~~

R-21 Area Lgt_02-01-2019

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-21.2 Sheet 2 of 3	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Lighting	
Part III. Rate Schedule No. 21		
Title: AREA LIGHTING (no new installations allowed)		PSC File Mark Only

Rate Modifier	Description	kWh	Monthly Rate Per Lamp
	Mercury Vapor		
326	700 Watt	257	$6.45~~10.65~~
327	1000 Watt	364	$9.51~~15.71~~
	Metal Halide		
336	400 Watt	156	$6.29~~10.40~~
337	1000 Watt	373	$7.87~~13.00~~
	High Pressure Sodium		
350	70 Watt	35	$4.88~~8.06~~
351	100 Watt	49	$4.90~~8.10~~
352	250 Watt	105	$5.66~~9.35~~
346	400 Watt	165	$6.27~~10.36~~
347	1000 Watt	388	$8.19~~13.53~~

Facilities Charge:

The Customer agrees to pay the following charge in addition to their monthly rate:

Mercury Vapor	1.46~~75~~% per month of Company's investment that is in excess of $154 per lamp
Metal Halide & High Pressure Sodium	1.46~~75~~% per month of the Company's investment to provide the lighting system

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-21.3	Sheet 3 of 3
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Lighting	
Part III. Rate Schedule No. 21		
Title: AREA LIGHTING (no new installations allowed)		PSC File Mark Only

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. R-22.1 Sheet 1 of 3

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: Lighting

Part III. Rate Schedule No. 22

Title: OUTDOOR LIGHTING

PSC File Mark Only

AVAILABILITY

No new mercury vapor installations will be allowed on this schedule on or after April 1, 2007. As existing mercury vapor fixtures and/or ballasts need to be replaced on or after April 1, 2007, the Customer will have the option to transfer to anothepr open tariff offering.

This rate is available to customers requesting outdoor area lighting service for private lighting systems, apartment projects, subdivisions, mobile home parks, parking lots, parks and grounds around buildings to be served from Company electric supply lines of adequate capacity and suitable voltage available, and where all the Customer's electricity requirements were purchased from the Company.

TYPE OF SERVICE

The Company will furnish, install, own, operate, and maintain a complete area lighting system of design and installation approved by the Company. The lights will be controlled to burn from dusk to dawn.

The Customer agrees to provide all required right-of-way together with tree trimming permits for installation of the system, and to protect the Company’s equipment from damage.

The Company shall have the right to build pole line and install equipment upon the Customer’s property and shall have access to the Customer’s premises for any other purpose necessary for the performance of this service. The facilities installed by the Company will remain the property of the Company and may be removed by Company upon discontinuance of service.

The Company will exercise reasonable diligence at all times to furnish Customer service as contracted for, but will not be liable for~~in~~ damages caused by~~for~~ any interruption, deficiency or failure of service. The Company reserves the right to interrupt the service when such interruption is necessary for repairs to its lines or equipment or the safe operation of those facilities.

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. R-22.2 Sheet 2 of 3

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: Lighting

Part III. Rate Schedule No. 22

Title: OUTDOOR LIGHTING

PSC File Mark Only

NET MONTHLY RATE

The Customer agrees to pay for service at the following rate:

Rate Modifier	Description	kWh	Monthly Rate Per Lamp
	Mercury Vapor		
400	175 Watt	68	$6.19~~10.23~~
401	400 Watt	155	$6.45~~10.65~~
	Metal Halide		
402	400 Watt	156	$6.29~~10.40~~
403	1000 Watt	373	$7.87~~13.00~~
	High Pressure Sodium		
404	100 Watt	49	$4.90~~8.10~~
405	250 Watt	105	$5.66~~9.35~~
406	400 Watt	165	$6.27~~10.36~~
407	1000 Watt	388	$8.19~~13.53~~
	Light Emitting Diode		
LED 01	0 - 100 Watts - Less than 10,000 lumens	20	$3.68
LED 02	101-250 Watts - 10,000-25,000	56	$5.54
LED 03	Over 250 Watts - Over 25,000	100	$9.41

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-22.3 Sheet 3 of 3	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Lighting	
Part III. Rate Schedule No. 22		
Title: OUTDOOR LIGHTING		PSC File Mark Only

Facilities Charge:

1.46~~43~~% per month of the Company's investment to provide each lighting system.

Adjustments:
Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatthour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

REPLACEMENT, REMOVAL, OR DISCONNECT

When a customer requests that the Company replace an existing non-LED lighting system with an LED lighting system the customer may be required to pay to the Company a one-time Conversion Fee of $95.

When a customer requests that the Company disconnect or remove an existing LED lighting system the customer may be required to pay to the Company a one-time Removal Fee of $145.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. R-23.1 Sheet 1 of 2

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: As Applicable

Part III. Rate Schedule No. 23

Title: Reserved for Future Use~~Rider C-1 Providing For Optional Reduced Commercial/Industrial/ Municipal Rate For Seasonal Electric Space Heating~~

PSC File Mark Only

This Schedule has been removed from the tariff book.

Reserved for Future Use

~~AVAILABILITY~~

~~This rider is available to Customers receiving electric service under the General Service (GS), Lighting and Power Service (LP), or Municipal Service (MS) Schedules having in regular use and permanently installed for heating either an electric reverse cycle central system heat pump or a total of 5 kilowatts or more of electric devices used for comfort space heating. The installation must be verified by Company personnel.~~

~~Space heating equipment served hereunder must be connected to a separate circuit which, during the heating season, shall not be used to supply service to equipment other than that for comfort space heating. Service delivered to the circuit supplying comfort space heating equipment will be metered separately from Customer's other service requirements.~~

~~Service under this rider is subject to all provisions of the applicable rate schedule to which it applies, except those provisions specifically modified herein.~~

~~THIS TARIFF EXPIRES AFTER THE APRIL 2011 BILLING CYCLE.~~

~~APPLICABILITY~~

~~This rider will be applicable in any year when Company's May through September maximum monthly system peak demand exceeds the preceding October through April maximum monthly system peak demand by 20%.~~

~~NET MONTHLY RATE~~

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Original Sheet No. R-23.2 Sheet 2 of 2

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: As Applicable

Part III. Rate Schedule No. 23

Title: Reserved for Future Use~~Rider C-1 Providing For Optional Reduced Commercial/Industrial/ Municipal Rate For Seasonal Electric Space Heating~~

PSC File Mark Only

~~Kilowatt-hour Charge:~~ ~~October through April Billing Cycles~~
~~$0.0217 per kilowatt-hour for all kilowatt-hours supplied to comfort space heating devices served on a separate circuit.~~

~~Adjustments:~~

~~Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatthour calculated according to the formula in the Energy Cost Recovery Rider – Arkansas.~~

~~Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider – Arkansas.~~

~~May through September Billing Cycles:~~

~~The kilowatt demand and kilowatthours supplied to the special space heating circuit will be billed under the applicable rate schedule to which this rider applies, and further, the kilowatt demand and the kilowatthours supplied to the special space heating circuit will be combined with the other service kilowatt demand and kilowatthours supplied, if any, for billing under the applicable rate schedule.~~

~~PAYMENT FOR SERVICE~~

~~Payment for Service Rider – See Rate Schedule 44.~~

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Original	Sheet No. R-24.1	Sheet 1 of 1
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 24		
Title: Rider C-2 Providing For Commercial/Industrial Seasonal Electric Space Heating		PSC File Mark Only

AVAILABILITY

This rider is available to Customers receiving electric service under the General Service (GS) or Lighting and Power Service (LP) Schedules having in regular use, permanently installed for heating either an electric reverse cycle central system heat pump or a total of 5 Kilowatts or more of electric devices used for comfort space heating. The installation must be verified by Company personnel.

Service under this rider is subject to all provisions of the applicable rate schedule to which it applies, except those provisions specifically modified herein.

APPLICABILITY

This rider will be applicable in any year when Company's May through September maximum monthly system peak demand exceeds the preceding October through April maximum monthly system peak demand by 20%.

KILOWATT CHARGE

During October through April billing cycles:

The Kilowatt charge will be computed using the Kilowatts of Billing Demand, which will be measured and will be the average kilowatt load used by the Customer during the 15-minute period of maximum use during the current month, but not to exceed the Kilowatts of Billing Demand established during the immediately preceding May through September billing cycles. However, the measured Kilowatts of Billing Demand for billing purposes will not be reduced by an amount greater than 60% of the kW load of the devices used for comfort space heating.

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Original	Sheet No. R-25.1	Sheet 1 of 1
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 25		
Title: TAX ADJUSTMENT RIDER		PSC File Mark Only

ARTICLE I:

Availability
This tariff schedule provides for the Company to pass directly to its customers within a municipality the proportionate part of any franchise or street rental taxes levied or imposed on the Company by that municipality on gross revenues from those customers.

Application
There shall be shown as a separate line item on each monthly bill for electric service to customers located within a municipality the amount of any street rental or franchise tax imposed or levied on the Company by the municipality on the gross revenues derived from the sale of electric power and energy to customer within the city limits of such municipality.

ARTICLE II:

Availability
In addition to all other charges, the amount of the Customer's bill will be increased by applicable sales taxes and other charges made effective by duly constituted authorities having jurisdiction.

Application
Each monthly bill for electric service to customers will include the amount of any sales tax and other charges levied or imposed by duly constituted authorities having jurisdiction over the customer for their electric usage.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-26.1	Sheet 1 of 4
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 26		
Title: MUNICIPAL TAX RATES		PSC File Mark Only

	Tax Rate		
	Applicable To:		
Municipality	Residential/Commercial	Industrial	Municipal
Ashdown	4%		
Avoca	2		
Bethel Heights	2		
Blevins	2		
Bonanza	4.25~~2.5~~		
Booneville	3		
Cave Springs	3		
Centerton	4		
Cove	2		
DeQueen	4		
Dierks	4		
Elm Springs	4.25~~2~~	4.25	
Eureka Springs	5		
Farmington	6		

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. R-26.2 Sheet 2 of 4

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: As Applicable

Part III. Rate Schedule No. 26

Title: MUNICIPAL TAX RATES

PSC File Mark Only

	Tax Rate		
Municipality	Applicable To: Residential/Commercial	Industrial	Municipal
Fayetteville	3	1	
Foreman	4		
Fouke	2		
Fulton	2		
Gillham	2		
Gravette	4	4	4
Greenland	2		
Greenwood	4.25~~4~~		
Hackett	4.25~~2~~		
Hartford	4.25		
Hatfield	2		
Horatio	4		
Huntington	4		
Johnson	4~~2~~		

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Original Sheet No. R-26.3 Sheet 3 of 4

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: As Applicable

Part III. Rate Schedule No. 26

Title: MUNICIPAL TAX RATES

PSC File Mark Only

	Tax Rate		
Municipality	Applicable To: Residential/Commercial	Industrial	Municipal
Lincoln	4.25		
Little Flock	4	1	
Lockesburg	2		
Lowell	4	1	
Magazine	4.25		
Mansfield	4		
McCaskill	4.25~~2~~		
Mena	4		
Midland	2		
Mineral Springs	4.25		
Murfreesboro	4.25~~2~~	4.25	
Nashville	4.25		
Ogden	2		
Ozan	2		
Pea Ridge	4		

R-26 Muni Tax_02-01-2019

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Original	Sheet No. R-26.4	Sheet 4 of 4
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 26		
Title: MUNICIPAL TAX RATES		PSC File Mark Only

	Tax Rate		
Municipality	Applicable To: Residential/Commercial	Industrial	Municipal
Prairie Grove	4.25		
Rogers	4	1	
Springdale	4	1	
Texarkana	6	4	6~~4~~
Waldron	4		
Washington	2		
West Fork	4.25		
Wilton	3		
Winthrop	2		

Note: Municipal Tax Amount is itemized on customer's bill as "MUNICIPAL FRANCHISE ADJ."

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

R-26 Muni Tax_02-01-2019

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Original	Sheet No. R-27.1 Sheet 1 of 12	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 27		
Title: ENERGY COST RECOVERY RIDER (RIDER ECR)		PSC File Mark Only

RECOVERY OF ENERGY COST

Energy Cost Recovery Rider ("Rider ECR ") defines the procedure by which the "Energy Cost Rate" of Southwestern Electric Power Company ("SWEPCO" or "Company") shall be initially established and periodically redetermined. The Energy Cost Rate shall recover the Company's net fuel and purchased energy cost, as defined in this Rider ECR.

ENERGY COST RATE

The Energy Cost Rate shall be redetermined annually through filings made in accordance with the provisions of Annual Redetermination of this Rider ECR. The Energy Cost Rate shall be applied to each customer's monthly billing energy (kWh). For electric service billed under applicable rate schedules for which there is no metering, the monthly usage shall be estimated by the Company and the Energy Cost Recovery Rider shall be applied. The Energy Cost Rate shall be calculated to the nearest $0.000001 and when applied to customers' bills shall be rounded to the nearest cent.

ANNUAL REDETERMINATION

On or before March 15 of each year the Company shall file a redetermined Energy Cost Rate with the Arkansas Public Service Commission (APSC or Commission). The redetermined Energy Cost Rate shall be determined by application of the Energy Cost Rate Formula set out in Attachment A of this Rider ECR. Each such revised Energy Cost Rate shall be filed in the proper underlying docket and shall be accompanied by a set of workpapers sufficient to fully document the calculations of the revised Energy Cost Rate.

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The redetermined Energy Cost Rate shall reflect the projected Energy Cost for the 12-month period commencing on April 1 of each year ("Projected Energy Cost Period") together with a true-up adjustment reflecting the over-recovery or under-recovery of the Energy Cost for the 12-month period ended December 31 of the prior calendar year ("Historical Energy Cost Period"). The Energy Cost Rate so determined shall be effective for bills rendered on and after the first billing cycle of April of the filing year and shall then remain in effect for twelve (12) months, except as otherwise provided for below.

The annual update shall include a report of the following:

1. detailed fuel and purchased energy costs by FERC account and month for the historical year;
2. identify and explain changes from the prior year for major cost components of the ECR Rider, including fuel expense, purchased energy expense, off-system sales margins, etc., of 10% or more;
3. identify changes in accounting procedures affecting fuel and purchased power costs, such as changes in FERC account number classifications and changes in costing methodologies;
4. identify changes in fuel and purchased power procurement practices;
5. identify the monthly level of coal inventory in days and tons for the historical year;
6. identify the average price per unit for each fuel type and purchased power for the historical year;

7. identify revisions to the AEP System Integration Agreement affecting fuel and purchased energy costs;

8. identify and discuss changes in environmental regulations affecting fuel and purchased energy costs and explain the Company's plans for compliance;

9. identify plant outages for the historical year and explain the cause(s) of the outages; and

10. provide the summation of all day-ahead and real-time transactions, centered around the SPP energy market, and forward transactions, which will be made outside the SPP energy market beyond the day-ahead time horizon, including total shareholder off-system sales margin allocations, for each month in the preceding calendar year.

ADJUSTMENTS

If prior to the annual redetermination of the Energy Cost Rate, Staff or the Company becomes aware of an event that is reasonably expected to occur and/or has occurred which will materially impact the Company's Energy Cost, either the Staff or the Company may propose an adjustment to the Energy Cost Rate Formula set out in Attachment A of this Rider ECR. Furthermore, should a cumulative over-recovery or under-recovery balance arise during any Rider Cycle which exceeds ten percent (10%) of the Historical Energy Cost Period, then either the APSC General Staff ("Staff") or the Company may propose an interim revision to the then currently effective Energy Cost Rate.

PAYMENT FOR SERVICE

Payment for Service Rider – See Rate Schedule 44.

ATTACHMENT A

ENERGY COST RATE FORMULA

ECR = ENERGY COST RATE

$$ECR = \frac{(TUA + (PEC * JAF) + DEFCON + M)}{PES} * LCF$$

WHERE,

$$TUA = \sum_{j=1}^{12} \left(\left(EC_j * JAF \right) - \left(RR_j - PTU_j \right) \right) + CC_j$$

Where,

EC_j = *ENERGY COST FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD (1)*

$$EC_j = Fe_j + Pe_j - MST_j + AR\ ADJ_j - ALLOWREV_j$$

ATTACHMENT A (continued)

Where

Fe_j	=	*FUEL EXPENSE CHARGED TO ACCOUNT 501 LESS ACCOUNT 501 COSTS THAT FIT THE DEFINITION OF FERC ACCOUNT 152 PLUS LIMESTONE, ACTIVATED CARBON, CALCIUM BROMIDE, HYDRATED LIME, AND UREA EXPENSE CHARGED TO ACCOUNT 502 PLUS SO_2 AND NO_X EMISSION COSTS CHARGED TO ACCOUNT 509, LESS FUEL, ENVIRONMENTAL CHEMICAL, AND EMISSION COSTS ASSOCIATED WITH OFF-SYSTEM SALES TRANSACTIONS IN MONTH j OF THE HISTORICAL ENERGY COST PERIOD (8,9,11)*
Pe_j	=	*PURCHASED <u>ENERGY</u> EXPENSE, CHARGED TO ACCOUNTS 555 (10), LESS FUEL COST ASSOCIATED WITH SALES TRANSACTIONS, IN MONTH j OF THE HISTORICAL ENERGY COST PERIOD, LESS THE CLECO PSSA PURCHASED ENERGY EXPENSE*
MST_j	=	*MARGINS FROM OFF-SYSTEM SALES TRANSACTIONS RECORDED IN MONTH j OF THE HISTORICAL ENERGY COST PERIOD (2)*
$AR\ ADJ_j$	=	*ADJUSTMENT FOR REMOVAL OF TURK PLANT EXPENSES AND REVENUES BECAUSE THE TURK PLANT DOES NOT SERVE ARKANSAS LOAD (9)*
$ALLOWREV_j$	=	*REVENUES ASSOCIATED WITH SALES OF SO_2 AND NO_X EMISSIONS ALLOWANCES RECORDED IN ACCOUNT 4118 AND REVENUES RECEIVED FROM THE SALE OF RENEWABLE ENERGY CREDITS,*

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Original	Sheet No. R-27.6	Sheet 6 of 12
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 27		
Title: ENERGY COST RECOVERY RIDER (RIDER ECR)		PSC File Mark Only

ATTACHMENT A (continued)

JAF = *JURISDICTIONAL ALLOCATION FACTOR (3)*

RR_j = *REVENUE UNDER RIDER ECR FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD*

PTU_j = *PRIOR PERIOD TRUE-UP ADJUSTMENT APPLICABLE FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD*

CC_j = *CARRYING CHARGES FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD*

$$CC_j = (BB_j + EB_j)/2 * CCR * DAYS_j/365$$

WHERE,

BB_j = *BEGINNING MONTH OVER/UNDER-RECOVERY BALANCE, EXCLUDING CARRYING CHARGES, FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD*

EB_j = *ENDING OVER/UNDER-RECOVERY BALANCE, EXCLUDING CARRYING CHARGES, FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD*

ATTACHMENT A (continued)

CCR = CARRYING CHARGE RATE (4)

$DAYS_j$ *= NUMBER OF DAYS IN MONTH j OF THE HISTORICAL ENERGY COST PERIOD*

PEC = *ESTIMATED ENERGY COST FOR THE PROJECTED ENERGY COST PERIOD (5)*

$$PEC = \sum_{j=1}^{12} EC_j$$

M = *$7,487 OF PROJECTED FINAL MINE CLOSING AND RECLAMATION COSTS FOR SWEPCO'S PIRKEY POWER PLANT*

LCF = *LOSS CORRECTION FACTOR (6)*

PES = *PROJECTED SALES (kWh) SUBJECT TO THIS RIDER ECR FOR THE PROJECTED ENERGY COST PERIOD*

DEFCON=AMORTIZATION OF DEFERRED CONSUMABLES ASSOCIATED WITH APSC DOCKET NO. 14-080-U

ATTACHMENT A (continued)

(1) The Historical Energy Cost Period is the calendar year immediately preceding the filing year.

(2) The margins from off-system sales transactions shall be treated in the following manner:

Customers shall be credited with 100% of the off-system sales margins allocated to SWEPCO's Arkansas retail jurisdiction up to $1,200,000 on an annual basis. For any off-system sales margins allocated to SWEPCO's Arkansas retail jurisdiction above $1,200,000, 90% of such margins shall be credited to customers and 10% of such margins shall be retained by the shareholders. Arkansas retail customers shall be shielded from any overall net annual loss from off-system sales transactions that may occur. In any year when the net margins from off-system sales result in a loss, such losses shall be borne by SWEPCO.

<u>Treatment of Affiliated Sales Margins</u>
Margins allocated to SWEPCO's Arkansas retail jurisdiction resulting from capacity sales will be reflected in the calculation of the Energy Cost Recovery Rider.

(3) The jurisdictional allocation factor will be derived in a two step process. First, for each jurisdiction the voltage level kWh at the meter will be divided by the most recent energy loss factors to determine the voltage level kWh at generation. Second, the Arkansas jurisdictional kWh at generation will be divided by the total kWh at generation for all jurisdictions less the Cleco PSSA kWh to develop the Arkansas jurisdictional allocation factor.

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ATTACHMENT A (continued)

(4) The Carrying Charge Rate shall be the Commission authorized interest rate on customer deposits.

(5) The Estimated Energy Costs for the Projected Energy Cost Period is equal to the energy costs for the Historical Energy Cost Period (the calendar year immediately preceding the filing year). Should there be unusual circumstances associated with any Projected Energy Cost or Projected Energy Cost Period either the Company or the Staff may propose use of a Projected Energy Cost (PEC variable) different from that defined by this formula.

(6) The loss correction factors will be determined by dividing the sum of the metered kWh sales for the Arkansas jurisdiction by the sum of the sales at the generation level for the Arkansas jurisdiction. This ratio of sales to generation is known as the “composite loss factor” for the Arkansas jurisdiction. The LCF for each voltage level is determined by dividing the service voltage loss factor by the composite loss factor.

(7) The deferred consumable balance under APSC Docket No. U-14-080-U as of the (insert date of new base rates) amortized over three years.

ATTACHMENT A (continued)

(8) Fuel Expense charged to Account 501 associated with the lignite supply to the Dolet Hills Power Plant will be treated in the following manner:

Treatment of the Dolet Hills Lignite Company Expenses

SWEPCO will be allowed to recover the costs associated with the Dolet Hills Lignite Company (DHLC) in the following manner:

Account 501 shall include costs associated with the DHLC mining operations in Month j of the Historical Energy Cost Period. DHLC services shall be provided at cost with the financing costs being calculated using the authorized rate of return on rate base most recently approved for SWEPCO by the APSC in a non-appealable final order on DHLC assets rather than DHLC's actual rate of return.

Production costs for DHLC shall be subject to the same ratemaking adjustments as applied to SWEPCO in a general rate case. Ratemaking adjustments shall include, but not be limited to:

- disallowance of charitable contributions and membership dues in civic organizations;
- disallowance of the portion of trade association memberships related to lobbying expenses and other disallowable costs;
- disallowance of expenses related to public relations advertising, image advertising, marketing, and corporate sponsorships;

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Original	Sheet No. R-27.11 Sheet 11 of 12	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 27		
Title: ENERGY COST RECOVERY RIDER (RIDER ECR)		PSC File Mark Only

ATTACHMENT A (continued)

- 50/50 sharing of directors' and officers' liability insurance expense between ratepayers and shareholders;
- disallowance of long-term incentive compensation related to stock performance;
- 50/50 sharing of incentive compensation related to financial incentives for operations between ratepayers and shareholders; and
- disallowance or sharing of similar costs allocated to DHLC by SWEPCO or American Electric Power Service Corporation.

SWEPCO shall provide a report with its annual Rider ECR filing that identifies the total costs reflected in invoices from DHLC and the ratemaking adjustments made to arrive at the amounts included in Fuel Expense for the Historical Energy Cost Period in sufficient detail to identify the items disallowed.

(9) *AR* ADJ_j as described in the definition above is an adjustment to Arkansas jurisdictional share of SWEPCO's total fuel cost for month (j). The detailed description of the adjustment effective with the implementation of the SPP IM is provided in the Direct Testimony and Exhibits of Naim Hakimi APSC Docket No. 14-022-TF, Page 9, Line 8 through Page 12, Line 6 and Exhibit ANH-4. The adjustment removes the Turk plant fuel cost (including related NO_x and SO_2 emissions costs) and associated revenues from sale of the Turk plant output in the SPP market from the Energy Cost.

ATTACHMENT A (continued)

(10) The recovery of energy costs associated with long-term renewable energy resources must be approved by the Commission prior to the recovery of costs through Rider ECR.

(11) No charges for activated carbon, calcium bromide, hydrated lime, or urea may be passed through the rider to customers unless the Commission has approved the prudence of the particular environmental controls project at issue or the Commission has otherwise approved the recovery of the costs for such a project in retail rates. Pursuant to Order No. 1 of Docket No. 14-080-U, SWEPCO shall defer the cost of activated carbon, calcium bromide, hydrated lime, and urea associated with the Dolet Hills and Pirkey power plants for serving Arkansas retail load incremental to the amount of chemical costs embedded in Arkansas retail rates without carrying charges.

AVAILABILITY

This schedule is available for Supplementary, Backup, Maintenance and As-Available Standby Power to customers that own and operate power production equipment or other source of power not held primarily for emergency use and that have a separate agreement for interconnection to Company's system stating those terms and conditions.

Service will be supplied at one point of delivery at locations where facilities of adequate capacity and suitable phase and voltage are available. Service may be provided on the Company's standard Contract for Electric Service, containing the Standard Terms and Conditions, stating the rate applicable to Supplementary Power and Energy, the Supplementary Power Contract Demand, the Backup Power Contract Demand, the Maintenance Power Contract Demand and the As-Available Standby Power Contract Demand that the Company is obligated to provide. The rate applicable to Supplementary Power and all energy is limited to the Lighting and Power Service Rate (LP), the Large Lighting and Power Service Rate (LLP), or the Pulp and Paper Mill Rate (P&PM), whichever is applicable. When used in conjunction with the Pulp and Paper Mill Rate, the Pulp and Paper Mill Rate will apply only to the Supplementary Power and all energy.

DEFINITIONS

Supplementary Power is electric capacity supplied by the Company, regularly used by a Customer in addition to that which the Customer's generation facility regularly generates. The Supplementary Power Billing Demand shall be determined in the Supplementary Power Charge section of this tariff.

Maintenance Power is electric capacity supplied by the Company during scheduled outages of the Customer's facility to replace capacity which is ordinarily generated by the Customer's own generation. This capacity when supplied during each of the months of October through May to Customers with total generating capacity of less than 5,000 kW shall be considered to be scheduled and approved by the Company as Maintenance Power until such time as the aggregate generation of all customer owned sources of power which are connected to the Company exceed 1% of the Company's peak system load. Customers with total generation capacity of 5,000 kW or greater must obtain written Company approval at least seven days in advance for a scheduled outage during the months of October through May or the use of capacity will be considered to be Supplementary Power. Maintenance Power will be supplied at the sole discretion of the Company, provided the

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Company is reasonably certain that a system peak will not be created during this period and providing the Company, in its judgment, has adequate capacity in its own system to supply the requested demand. Maintenance Power will normally not be available during the months of June through September.

Maintenance Power Demand is the Kilowatts of Billing Demand that exceed the Supplementary Power Billing Demand during the period approved for maintenance power usage. If As-Available Standby Power has been requested during this period, then for billing purposes, the Maintenance Power Demand will be equal to the Maintenance Power Contract Demand.

Backup Power is electric capacity supplied by the Company during an unscheduled outage of the Customer's facility to replace capacity ordinarily provided by the Customer's own generation. However, any capacity supplied by the Company during an unscheduled outage of the Customer's facility to replace that which is ordinarily provided by the Customer's own generation during the months of June through September shall be considered as Backup Power, and/or As-Available Standby Power if approved by the Company. The Customer shall notify the Company's system dispatcher as soon as reasonably possible when requesting the initiation and termination of Backup Power. The customer shall also provide written documentation to the Company within 24 hours or on the first working day following a weekend or holiday confirming the date and time of both the initiation and termination of Backup Power.

Backup Power Demand is the Kilowatts of Billing Demand that exceed the Supplementary Power Billing Demand during the period of Backup Power usage. If As-Available Standby Power has been requested during this period, then for billing purposes, the Backup Power Demand will be equal to the Backup Power Contract Demand.

Kilowatts of Billing Demand for each month will be the average kilowatt load used by the Customer during the 15-minute period of maximum use during the month.

As-Available Standby Power is electric capacity supplied by the Company during a scheduled or unscheduled outage of the Customer's facility to replace capacity which is provided by the Customer's own generation. Customer may request As-Available Standby Power at any time subject to the conditions specified herein. However, the Customer must request and receive prior approval from Company each time As-Available Standby Power is required and must also notify the Company

when As-Available Standby Power is to be discontinued. When Customer experiences a forced outage of his power production facilities, Customer must request approval from Company's dispatcher for continued use of As-Available Standby Power after the forced outage has occurred and use of As-Available Standby Power has begun. This provision for after-the-fact request and approval shall apply only if Customer has contacted the Company's system dispatcher for approval as soon as reasonably possible. All requests for and terminations of As-Available Standby Power shall be confirmed in writing to the Company by the Customer within 24 hours of the request or termination. As-Available Standby Power will be available solely at the discretion of the Company. At the request of Company, the Customer will cease use of As-Available Standby Power within ten (10) minutes after notification from the Company that approval for continued use of that As-Available Standby Power is denied. Use of As-Available Standby Power will be subject to immediate interruption for emergency system conditions.

As-Available Standby Power Demand is the kilowatts of capacity requested by the Customer. This capacity is requested in addition to any capacity associated with Supplementary, Backup, or Maintenance Power during the period of Backup or Maintenance Power usage.

MONTHLY RATE

The monthly billing shall be the sum of the following:

(I) Supplementary Power Charge
(II) Backup Power Charge and Maintenance Power Charge
(III) As-Available Standby Power Charge
(IV) Energy Charge

(I) SUPPLEMENTARY POWER CHARGE

The applicable rate schedule for supplementary power, with modifications to the provisions for the Determination of Kilowatts of Billing Demand and the Power Factor Adjustment, as specified herein, will be applied to any and all electric capacity actually supplied by the Company during the month, except for any Maintenance Power Demand, any Backup Power Demand, and any As-Available Standby Power Demand.

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Original	Sheet No. R-28.4 Sheet 4 of 8	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 28		
Title: Supplementary, Backup, Maintenance, and As-Available Standby Power Service		PSC File Mark Only

Determination of Supplementary Power Billing Demand

When neither Backup, Maintenance, nor As-Available Standby Power are being used, the Supplementary Power Billing Demand will be the Kilowatts of Billing Demand established by the Customer, subject to the Kilowatts of Billing Demand provisions specified in the Lighting and Power Rate, the Large Lighting and Power Rate, or the Pulp and Paper Mill Rate, whichever is applicable. When Backup, Maintenance, or As-Available Standby Power is taken in conjunction with Supplementary Power, the Supplementary Power Billing Demand will be the greatest of:

A. Supplementary Power Contract Demand as specified in the Contract for Electric Service;
B. The Kilowatts of Billing Demand less the Backup Power Contract Demand when Backup Power is being used, less the Maintenance Power Contract Demand when Maintenance Power is being used, less the As-Available Standby Power Demand requested;
C. Supplementary Power Billing Demand of the current month;
D. Seventy percent (70%) of the highest Supplementary Power Billing Demand of the previous eleven months for customers receiving service under the LP rate schedule, eighty percent (80%) of the highest Supplementary Power Billing Demand of the previous eleven months for customers receiving service under the LLP rate schedule, or the highest Supplementary Power Billing Demand in the 12-month period ending with the current month for customers receiving service under the P&PM rate schedule.

(II) BACKUP POWER CHARGE AND MAINTENANCE POWER CHARGE

The monthly billing for Backup Power and Maintenance Power shall be the sum of (A) the Backup Power Charge, plus (B) the Maintenance Power Charge. However, this amount shall not be less than (C) the Minimum Monthly Charge for Backup Power and Maintenance Power.

(A) BACKUP POWER CHARGE

Company agrees to supply Backup Power up to but not exceeding the Backup Power Contract Demand. The Backup Power Contract Demand shall not exceed the nameplate rating of the Customer's generating unit(s) unless the Customer can demonstrate a higher capability for its unit(s). The Backup Power Contract Demand can be adjusted annually with written request by the Customer and with written consent of the Company.

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Original	Sheet No. R-28.5	Sheet 5 of 8
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 28		
Title: Supplementary, Backup, Maintenance, and As-Available Standby Power Service		PSC File Mark Only

Daily Rate for Backup Power
The Daily Rate for Backup Power will be the Kilowatts of Backup Power Demand times the applicable rate:

Pulp & Paper Mill Transmission Service	$0.31~~22~~
Large Lighting & Power Transmission Service	$0.31~~22~~
~~Large Lighting & Power Primary Service~~	~~$0.28~~
Lighting & Power Primary Service	$0.46~~28~~
Lighting & Power Secondary Service	$0.50~~30~~

(B) MAINTENANCE POWER CHARGE
The Company agrees to supply Maintenance Power up to but not exceeding the Maintenance Power Contract Demand. Maintenance Power Contract Demand shall not exceed the nameplate rating of the Customer's generating unit(s) unless Customer can demonstrate a higher capability for its unit(s). The Maintenance Power Contract Demand can be adjusted annually with written request by the Customer and with written consent of the Company. Upon approval by the Company, Maintenance Power may be scheduled for a total of three occurrences in a calendar year during the months of January through May and October through December for each of the Customer's generating unit(s) provided Customer provides the Company at least seven days prior notice of intent to perform maintenance. In the event maintenance exceeds the scheduled time period provided by the Customer and agreed to by the Company or exceeds a maximum of 30 days per generating unit per calendar year, unless it is agreed to extend Maintenance Power or supply Backup Power, by written request by the Customer and written consent of the Company, such excess use of capacity will be billed as Supplementary Power.

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Original	Sheet No. R-28.6	Sheet 6 of 8
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 28		
Title: Supplementary, Backup, Maintenance, and As-Available Standby Power Service		PSC File Mark Only

Daily Rate for Maintenance Power

The Daily Rate for Maintenance Power will be the Kilowatts of Maintenance Power Demand times the applicable rate:

Pulp & Paper Mill Transmission Service	$0~~.~~18~~12~~
Large Lighting & Power Transmission Service	$0.18~~12~~
~~Large Lighting & Power Primary Service~~	~~$0.12~~
Lighting & Power Primary Service	$0.18~~12~~
Lighting & Power Secondary Service	$0.22~~15~~

(C) MINIMUM MONTHLY CHARGE FOR BACKUP POWER AND MAINTENANCE POWER

The Minimum Monthly Charge for Backup Power and Maintenance Power shall be the applicable monthly rate per kW of Backup Power Contract Demand plus the applicable monthly rate per kW of Maintenance Power Contract Demand in excess of the Backup Power Contract Demand.

Backup Power - Minimum Charge Per kW:

Pulp & Paper Mill Transmission Service	$1.33~~0.91~~
Large Lighting & Power Transmission Service	$1.33~~0.91~~
~~Large Lighting & Power Primary Service~~	~~$2.55~~
Lighting & Power Primary Service	$4.23~~2.55~~
Lighting & Power Secondary Service	$4.42~~2.63~~

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-28.7	Sheet 7 of 8
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 28		
Title: Supplementary, Backup, Maintenance, and As-Available Standby Power Service		PSC File Mark Only

Maintenance Power - Minimum Charge Per kW:

Pulp & Paper Mill Transmission Service	$0.68~~46~~
Large Lighting & Power Transmission Service	$0.68~~46~~
~~Large Lighting & Power Primary Service~~	~~$1.27~~
Lighting & Power Primary Service	$2.11~~1.27~~
Lighting & Power Secondary Service	$2.22~~1.32~~

(III) AS-AVAILABLE STANDBY POWER CHARGE
The Company agrees to supply As-Available Standby Power up to but not exceeding the As-Available Standby Power Contract Demand. The As-Available Standby Power Contract Demand shall not exceed the nameplate rating of the Customer's generating unit(s) unless the Customer can demonstrate a higher capability for its unit(s). The As-Available Standby Power Contract Demand can be adjusted annually with written request by the Customer and with written consent of the Company.

Monthly Rate for As-Available Standby Power
The monthly rate for As-Available Standby Power will be the As-Available Standby Power Demand times the applicable rate:

Pulp & Paper Mill Transmission Service	$0.47~~32~~
Large Lighting & Power Transmission Service	$0.47~~32~~
~~Large Lighting & Power Primary Service~~	~~$1.18~~
Lighting & Power Primary Service	$1.96~~1.18~~
Lighting & Power Secondary Service	$2.04~~1.21~~

ARKANSAS PUBLIC SERVICE COMMISSION

(IV) ENERGY CHARGE

The monthly rate for all energy used during the month will be the kilowatt~~-~~hour charge as set forth in the Lighting and Power Rate, Large Lighting and Power Rate, or Pulp and Paper Mill Rate, whichever is applicable.

Power Factor Adjustment - Kilovar Charge

The kilovars of Reactive Demand will be recorded each month by the Company and will be the average kilovars used by the Customer during the 15-minute period of maximum kilovar use during the month. A Generation Function Charge of $0.54~~34~~ per month shall be made for each Kilovar of Reactive Demand exceeding 50% of the Kilowatts of Billing Demand.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service provided under the terms of this tariff will be furnished under the Company's Standard Contract containing the Standard Terms and Conditions and will be recognized as an exemption to the Exclusive Service Clause of the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-29.1 Sheet 1 of 1	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 29		
Title: CHARGES FOR SPECIAL OR ADDITIONAL FACILITIES		PSC File Mark Only

In the event facilities in excess of a normal installation are found to be required to serve the Customer's load, or are requested by the Customer and approved by the Company, the Company shall furnish, install, and maintain such facilities with a monthly charge to the Customer according to the following schedule:

1. A monthly charge of 1.46~~43~~% will be applied to the total investment in facilities that are installed, owned, operated and maintained by the Company.

2. The monthly charge rate for maintaining facilities installed and owned by the Company but for which Customer has paid the full amount to Company will be 0.69~~60~~% of the total investment in the facilities.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-30.1	Sheet 1 of 1
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 30		
Title: TEMPORARY SERVICE		PSC File Mark Only

Service furnished for loads that are of a temporary nature, such as construction power, asphalt batch plants, carnivals, temporary commercial and industrial establishments, and others, will be billed on the applicable rate and the Customer will pay the Company the cost of installation and removal labor and unsalvageable materials including overhead costs.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-31.1 Sheet 1 of 4	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 31		
Title: CHARGES RELATED TO CUSTOMER ACTIVITY		PSC File Mark Only

TERMS AND CONDITIONS

Services under this tariff are provided in accordance with the Company's Standard Terms and Conditions.

CHARGES RELATED TO CUSTOMER ACTIVITY

Customer Account Record Statement (General Service Rule (GSR) 2.04.A.)
The Company will charge a fee of: -- No Charge
when a customer or any authorized party requests a statement of the customer's account record as described by GSR 7.02.

Energy Consumption Statement (GSR 2.04.B.)
The Company will charge a fee of: -- No Charge
when a customer or any authorized party requests a statement of the customer's energy consumption for the preceding 13 months.

Deposit From Applicant (GSR 4.01.A. & B.)
The Company may require a deposit from any applicant to guarantee payment for service, subject to the conditions of GSR 4.01 in Subsections A. & B.

Deposit From Landlord (GSR 4.01.A. & B.(1))
The Company may require a deposit when an applicant for residential service qualifies as a landlord as defined in the APSC General Service Rules. The amount of the deposit will be calculated in accordance with GSR 4.01.B(1).

Deposit From Customer (GSR 4.02.A. & B.)
The Company may require a deposit from a customer when that customer meets the criteria in GSR 4.02.A.

The amount of the deposit will be calculated in accordance with GSR 4.02.B.

ARKANSAS PUBLIC SERVICE COMMISSION

Processing Fee For Levelized Billing Withdrawal (GSR 5.10.C(3))
The Company will require payment of a processing fee of: -------------------------- No Charge
if a customer withdraws from a levelized billing plan more than one time in 12 months.

Returned Check Charge (GSR 5.13.)
The Company will charge a returned check fee when a customer pays by check and the check is returned to the Company for any reason other than bank error. ---------$25.00

Meter Reading Report Charge (GSR 5.16.B(3))
The Company will charge a meter reading report fee of: -------------------------- No Charge
if a customer has requested a meter reading report in writing and the customer has already received two free meter reading reports in the last 12 months.

Meter Test Fee (GSR 5.18.C.(1))
The Company will charge a meter test fee when a customer's meter has been tested in accordance with the procedures set out in GSR 5.18., and the meter test results show the meter to be operating within the guidelines of Rule 7.05. of the Special Rules - Electric.

Self Contained ---$35.00
Other --$59.00

Collection Fee (GSR 6.11.)
The Company will charge a fee when the last day to pay, as printed on the most recent cut-off notice, has passed and a utility employee accepts payment at the premises under GSR 6.09.B(1) without service being disconnected. -----------$10.00

ARKANSAS PUBLIC SERVICE COMMISSION

Reconnection Fee (GSR 6.12.)

The Company will charge a reconnect fee when a customer or other authorized party requests reconnection during normal working hours, and payment is made at a Company business office or payment agency before the Company's close of business on the same day. ---$25.00

The Company will charge a reconnect fee when a customer or other authorized party requests reconnection on a pole during normal working hours, and payment is made at a Company business office or payment agency before the Company's close of business on the same day. ---$74.00

Finance Charge on Delayed Payment Agreements (GSR 6.13.I)

The finance charge on delayed payment agreements will be interest as defined by the GSR. --No Charge
(The rate is set annually by the Commission.)

Meter Tampering

The Company will charge a fee if customer connects a meter that has been cut off by Company.

During regular working hours--$75.00
During other than regular working hours--$97.00

The Company will charge a minimum fee for a broken meter seal and/or meter tampering. --$57.00

Connection Other Than Regular Working Hours

The Company will charge a fee for initiation of permanent service (if no construction is required) during other than regular working hours. ------------------$57.00

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-31.4	Sheet 4 of 4
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 31		
Title: CHARGES RELATED TO CUSTOMER ACTIVITY		PSC File Mark Only

Re-fusing Customer's Circuits
The Company will charge a service charge plus the price of fuses for re-fusing customer's circuits. --$42.00

Faulty Customer-Owned Equipment
A service charge will be charged during regular business hours where trouble is found to be in customer's equipment. --$82.00

A service charge will be charged after regular business hours where trouble is found to be in customer's equipment. ---$106.00

Relocation Fee
A facilities relocation fee (actual cost of labor and materials used) will be charged to customers requesting the relocation of Company's facilities. ----------Actual Cost

Translation and Non-Standard Reports (minimum charge)
The Company will charge a fee each time the Company provides meter pulse translation and any non-standard reporting requested by the customer. -----------------$25.00

Connect Fee
The Company will charge a fee each time a meter must physically be re-set or pulled and re-set. This fee does not apply to connects requiring only a read-out/read in. ----$10.00

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

OPTION 1

Availability

This ~~rider~~ Option 1 is only available to customers receiving electric service under the Lighting and Power Service (LP) or Large Lighting and Power Service (LLP) rate schedules. ~~This~~ Option 1~~rider~~ is available to new loads of 500 kW or more, or significant expansions of existing load in excess of ~~the Kilowatts (kW) or~~ 500 kW~~5%~~ ~~of~~ incremental~~existing~~ load, or for resumption of service to loads of a minimum of 500 kW which have been inactive for 12 months or more. Service under ~~this~~ Option 1~~rider~~ is available only in conjunction with a contract for electric service having a minimum initial term of five~~six~~ years and requiring a minimum of thirty (30) days advance notice to cancel thereafter.

To qualify for ~~this~~ Option 1~~rider~~, the customer must furnish to the Company an affidavit stating that this rider was an important factor in the customer's decision to add new or incremental~~additional~~ load or to resume load that has been inactive for 12 months or more, and complete and sign the appropriate application form.

The load factor of the entire facility, including expansion, must be equal to or greater than 40%.

~~This rider is not available to additional load from customers who have begun construction or installation of equipment prior to the date of approval of this rider.~~

The availability of ~~this~~ Option 1~~rider~~ is at the sole discretion of the Company. T~~, and t~~he Company will not accept new applications for service under Option 1~~this rider~~ when the Company's forecasts indicate that additional generating capacity will be needed within a three~~six~~-year period.

All provisions of the LP or LLP rate schedules, whichever is applicable, will apply except as modified herein.

Definition of Base Period

The Base Period shall be the 12 months immediately preceding the month that service is requested under this rider, or as mutually agreed upon by the Company and the Customer.

Determination of ~~Monthly~~ Base Threshold Demand ~~Threshold~~

For expansions, t~~T~~he ~~Monthly~~ Base Threshold Demand ~~Threshold~~ shall be determined based ~~y~~ on~~increasing~~ the Kilowatts of Billing Demands ~~for each month~~ of the Base Period ~~by the greater of 500 kW or 5% of existing load~~. For ~~a~~ new Customers or for Customers resuming service to loads which have been inactive for 12 months or more, the Monthly Base Threshold Demand ~~Threshold~~ shall be 0~~500~~ kW. The Kilowatts of Billing Demand for each month of the Base Period may be

adjusted as mutually agreed upon by the Company and the Customer to reflect the Customer's normalized load profile.

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. R-32.3 Sheet 3 of 5

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: As Applicable

Part III. Rate Schedule No. 32

Title: EXPERIMENTAL ECONOMIC DEVELOPMENT RIDER

PSC File Mark Only

Determination of Economic Development Demand

The Economic Development Demand subject to the provisions of Option 1 ~~this rider~~ shall be that portion of the Kilowatts of Billing Demand during the current month that is greater than the Monthly Base Threshold Demand ~~Threshold of the corresponding month in the Base Period~~.

Determination of Economic Development Credits

The Customer's monthly bill for service under Option 1~~this rider~~ will be calculated in accordance with the LP or LLP rate schedule,~~,~~ whichever is applicable, with the exception that an Economic Development Credit will be applied. An Economic Development Credit will be determined by multiplying the Economic Development Demand times the Kilowatt Charge of the LP or LLP rate schedule, whichever is applicable, times the appropriate Billing Credit Factor. The Billing Credit Factors are provided below:

Term of Economic Development Credit	Billing Credit Factors
Year 1 - First 12 monthly billing periods	50%
Year 2 - Next 12 monthly billing periods	40%
Year 3 - Next 12 monthly billing periods	30%
~~Year 4 - Next 12 monthly billing periods~~	~~20%~~
~~Year 5 - Next 12 monthly billing periods~~	~~10%~~

Special Terms and Conditions

In the event the monthly Kilowatts of Billing Demand for 12 consecutive months is less than the corresponding ~~Monthly~~ Base Threshold Demand ~~Threshold~~, this rider will automatically terminate. Billing for subsequent months will revert to the LP or LLP rate schedule, whichever is applicable.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-32.4	Sheet 4 of 5
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 32		
Title: EXPERIMENTAL ECONOMIC DEVELOPMENT RIDER		PSC File Mark Only

OPTION 2

Availability

This Option 2 is only available to customers receiving electric service under the Lighting and Power (LP) rate schedule. Option 2 is available to new loads of 200 kW or more. Service under Option 2 is available only in conjunction with a contract for electric service having a minimum initial term of five years and requiring a minimum of thirty (30) days advance notice to cancel thereafter.

Examples of businesses and industries eligible for service under Option 2 include the following categories:

- Distribution centers
- Startup manufacturing
- Big Box and/or retail stores
- Server farms and other information technology related companies
- Printing companies

To qualify for Option 2, the customer must furnish to the Company an affidavit stating that this rider was an important factor in the customer's decision to add load and complete and sign the appropriate application form.

The load factor of the facility must be equal to or greater than 40%.

The availability of Option 2 is at the sole discretion of the Company. The Company will not accept new applications for service under Option 2 when the Company's forecasts indicate that additional generating capacity will be needed within a three-year period.

All provisions of the LP rate schedule will apply except as modified herein.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-32.5 Sheet 5 of 5	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 32		
Title: EXPERIMENTAL ECONOMIC DEVELOPMENT RIDER		PSC File Mark Only

Determination of Base Threshold Demand
The Monthly Base Threshold Demand shall be 0 kW.

Determination of Economic Development Demand
The Economic Development Demand subject to the provisions of Option 2 shall be that portion of the Kilowatts of Billing Demand during the current month that is greater than the Monthly Base Threshold Demand. The Economic Development Demand will not exceed 500 kW.

Determination of Economic Development Credits
The Customer's monthly bill for service under this rider will be calculated in accordance with the LP rate schedule with the exception that an Economic Development Credit will be applied. An Economic Development Credit will be determined by multiplying the Economic Development Demand times the Kilowatt Charge of the LP rate schedule times the appropriate Billing Credit Factor. The Billing Credit Factors are provided below:

Term of Economic Development Credit	Billing Credit Factors
Year 1 - First 12 monthly billing periods	35%
Year 2 - Next 12 monthly billing periods	25%
Year 3 - Next 12 monthly billing periods	15%

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	**Sheet No:** R-33.1	Sheet 1 of 4
Replacing:	**Sheet No:** R-33.1	
Name of Company: SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	**Class of Service:** As Applicable	
Part III. Rate Schedule No. 33		
Title: PURCHASED POWER SERVICE (PPS)		

PSC File Mark Only

AVAILABILITY

This rate shall apply to purchases by the Company of energy generated by qualified small power production and cogeneration facilities. The Qualified Facility's (QF) electrical requirements supplied by the Company shall be separately metered and billed in accordance with the applicable rate schedule. The rules under which small power production and cogeneration facilities can obtain qualifying status are defined in the Arkansas Public Service Commission Cogeneration Rules as approved. The design capacity of the qualified facility must be 100 kW or less.

PAYMENT SCHEDULE

The payment shall be the algebraic sum of calculations made under (I) and (II) below.

(I) RATE

(A) QF Charge (Payable by QF)

(1) Each QF will pay any interconnection costs which are defined as the costs of connection, switching, metering, transmission, distribution, safety provisions, and administrative costs incurred by the Company directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations. Interconnection costs do not include any costs included in the calculation of avoided costs in Section (I)(B). The QF will either make an initial payment to the Company for the interconnection costs for investment in facilities as determined above or make periodic payments over a two year period wherein such payments provide for the amortization of interconnection costs, as well as a return to the Company equal to its pre-tax

ARKANSAS PUBLIC SERVICE COMMISSION

Revision 9 **Sheet No:** R-33.2 Sheet 2 of 4

Replacing: Revision 8 **Sheet No:** R-33.2

Name of Company: SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric **Class of Service:** As Applicable

Part III. Rate Schedule No. 33

Title: PURCHASED POWER SERVICE (PPS)

PSC File Mark Only

marginal cost of capital. In addition, the QF will pay the monthly charge for maintaining facilities currently at the filed rate of 0.69~~54~~ percent of the interconnection cost for investment in facilities as determined above.

(2) Monthly QF Charge (Payable by QF)
Each QF will pay a monthly QF Charge of $12.00. This charge is to cover such items as customer accounting expenses, administrative expenses, and general expenses incurred in servicing the QF.

(B) Monthly kWh Payment (Payment by Company)
Payment for energy delivered into Company's system with adjustment as provided in (II) will be at the following purchase rate:

Months – 2019	cents/KWH
1st Quarter - January, February, March	3.1164
2nd Quarter - April, May, June	2.4095
3rd Quarter - July, August, September	2.7714
4th Quarter - October, November, December	2.3866

Purchase rate will begin upon approval of the Purchased Power Service (PPS) rate schedule and will be revised no less frequently than annually.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	**Sheet No:** R-33.3	Sheet 3 of 4
Replacing:	**Sheet No:** R-33.3	
Name of Company: SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	**Class of Service:** As Applicable	
Part III. Rate Schedule No. 33		
Title: PURCHASED POWER SERVICE (PPS)		

PSC File Mark Only

(II) ADJUSTMENTS

(A) (Meter readings may be made in conjunction with regular meter reading schedules. The actual metered kilowatt-hours will be billed according to the pricing period defined in (I)(B). Kilowatt-hour payments will be prorated to reflect the number of days within each quarter and each pricing period when metering does not allow for an actual determination.

BILLING

The Company shall send a statement to the QF on or before the 10th day after the QF's meter is read. The statement will show the kilowatt capacity, if any, and kilowatt-hours delivered to the Company during the period, customer charges payable to the Company, and total amount due. Payments for service will be rendered monthly, unless otherwise specified. The term "month" for payment purposes will mean the period between any two consecutive readings of the meters by the Company, such readings to be taken as nearly as practical every 30 days. The Company reserves the right to credit purchase of power against billings for electric service due and payable to the Company by the QF.

CONTRACT PERIOD

A Power Purchase Contract will be in effect for each service at each separate location. The Contract Period shall be negotiated between the QF and the Company. The Company's TERMS AND CONDITIONS FOR PURCHASE BY THE COMPANY OF ELECTRICITY APPLICABLE TO RATE SCHEDULE PURCHASED POWER SERVICE (PPS) are applicable to this rate schedule.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	**Sheet No:** R-33.4	Sheet 4 of 4
Replacing:	**Sheet No:** R-33.4	

Name of Company: SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric **Class of Service:** As Applicable

Part III. Rate Schedule No. 33

Title: PURCHASED POWER SERVICE (PPS)

PSC File Mark Only

SUPPLEMENTARY POWER SERVICE

Supplementary power is electric energy or capacity used regularly by a facility in addition to that power which it ordinarily generates for its own use. QF's electrical requirements for supplementary power service will be supplied by the Company and shall be separately metered and billed in accordance with the applicable rate schedule and the Company's Standard Terms and Conditions.

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ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. R-34.1 Sheet 1 of 1

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: All

Part III. Rate Schedule No. 34

Title: REDUNDANT SERVICE POLICY FOR MUNICIPAL ACCOUNTS

PSC File Mark Only

AVAILABILITY

Redundant service is defined as those facilities, including metering equipment, to provide electric power and energy from an alternate source to municipal accounts served by the Company that require such redundant service.

APPLICABILITY

The kilowatt-hours used on the meter for redundant service plus the kilowatt-hours equal to the redundant transformer no load losses at 100% voltage shall be added to the kilowatt-hours used on the regular meter (for billing on the appropriate rate) plus a charge computed according to one of the Alternatives:

ALTERNATIVE 1 For Total Company Investment to Provide Redundant Service

There will be a charge each month equal to 1.46~~43~~% (17.52~~17.21~~% per year) of the Company investment, which includes metering costs, to provide redundant service.

ALTERNATIVE 2 For Customer's Contribution of the Total Investment to Provide Redundant Service

There will be a charge each month equal to 0.69~~60~~% (8.28~~7.16~~% per year) of the Customer's contribution of the total investment to provide redundant service.

ALTERNATIVE 3 For the Customer Desiring to Make a Contribution in Aid of Construction Toward the Investment Required to Provide the Redundant Service

There will be a charge each month equal to 1.46~~43~~% (17.52~~17.21~~% per year) of the Company's investment, which includes metering costs, to provide redundant service plus a charge each month equal to 0.69~~60~~% (8.28~~7.16~~% per year) of the Customer's contribution toward the investment required to provide the redundant service.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under Company's Standard Terms and Conditions.

THIS SPACE FOR PSC USE ONLY

For Residential Customers in Undeveloped Areas:

Southwestern Electric Power Company's (SWEPCO) philosophy is to extend facilities to provide service requested under the applicable rate schedule. If the anticipated continuing annual revenue, not including adjustment charge of fuel and tax adjustment charge, will not support the allocated portion of SWEPCO's investment in facilities to extend or provide service in undeveloped areas, the following extension policy will apply.

When the revenue from the prospective customer(s) does not meet these estimated criteria, the Company will be authorized to collect a minimum bill which will be determined by such factors as: cost of extension (not including system investment and cost of meter), growth potential, future earnings, system improvements, terrain, geography and other considerations.

The customer will be billed for electric service made available hereunder on the published rate schedule applicable to the location. However, for the amount of investment determined by the Company, customer agrees to pay the Company a minimum amount of $________ per month (1/60th of the allocated portion of SWEPCO's investment) plus the fuel adjustment charge and the tax adjustment charge as provided in the rate schedule for a period of five years from the date service is first made available to the customer from said extension. The customer agrees to pay said minimum monthly amount to the Company. Customer further agrees to pay said minimum monthly amount even though it may be in excess of the amount specified in Company's applicable published rate schedule. If the premises served under this agreement are sold, leased, or rented, the customer nevertheless guarantees the payment of said minimum bill for said period, as provided above.

For Industrial, Large Commercial and Loads Requiring an Unusual Amount of Investment

SWEPCO will own, install, operate and maintain the facilities required to supply the customer's electric requirements. Electric service will be furnished according to terms of a contract between the parties including the applicable rate schedule plus a provision which will provide:

In consideration of the determined investment in facilities by SWEPCO necessary to make electric service available, the customer agrees to pay to SWEPCO each month an amount, computed under the applicable rate schedule not including tax adjustment charge, the cost of fuel and/or fuel adjustment revenue, not less than 1/60th* of the determined investment required to supply the customer's electrical requirements. The determined investment will include such factors as cost of extension (including system investment), growth potential, future earnings, system improvements, terrain, geography and other considerations.

*The denominator of this fraction is to be the number of months for which service is contracted if less than 60 months.

Contribution in Aid of Construction

The customer may reduce the minimum bill requirement by making a contribution in aid of construction to reduce the determined investment to not more than five times the anticipated continuing annual revenue, not including the fuel adjustment charge and tax adjustment charge.

Contributions in aid of construction that are considered taxable income by a governmental agency or body will be increased by the approximate tax rate.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under Company’s Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-36.1	Sheet 1 of 5
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 36		
Title: EXPERIMENTAL CURTAILABLE SERVICE RIDER		PSC File Mark Only

AVAILABILITY

This Rider is available only in conjunction with Company's Lighting and Power (LP) or Large Lighting and Power (LLP) rate schedules to Customers who contract for not less than 500 kW of curtailable power. The applicable rate schedule will be determined based on the Customers Total kW. All provisions of the Lighting and Power or Large Lighting and Power rate schedules, whichever is applicable, will apply except as modified herein. Service must be taken at one point of delivery and measured through one meter. This Rider is not available for backup power to customer owned generation. This Rider is not applicable in conjunction with Company's Experimental Economic Development Rider for loads designated as Curtailable kW.

The availability of service under this Rider is subject to the Company, in its sole judgment, having sufficient capacity and fuel to serve the requirements of its other customers and to maintain its spinning reserve. The availability of total system curtailable and interruptible kW contracted may be limited by the Company to an amount not to exceed 5% of the projected aggregate Company peak demand. Service is available under this Rider only if the utilization of such service is of such character that service can be curtailed at any time by Company, following 10 minutes notice by Company to Customer that service must be curtailed, without loss to Customer or damage to property or persons and without adversely affecting the public health, safety, and welfare.

DEFINITION OF TERMS

Total kW: Total kW is defined as the sum of the Firm kW and the Curtailable kW designated by the customer when contracting for service under this Rider and will be used to determine the applicable rate schedule.

Firm kW: Firm kW is defined as that portion of the Total kW that is not subject to curtailment under the terms and conditions of this Rider. The Firm kW will be designated by the Customer when contracting for service under this Rider. In addition, Firm kW may be adjusted annually by the Customer by written request to the Company.

ARKANSAS PUBLIC SERVICE COMMISSION

Curtailable kW: Curtailable kW is defined as that portion of the Total kW subject to curtailment by the Company under this Rider. The Curtailable kW will be designated by the Customer when contracting for service. In addition, Curtailable kW may be adjusted annually by the Customer by written request to the Company.

CONDITIONS OF SERVICE

Customer may choose to have Total kW or some portion thereof designated as Curtailable kW. The amount of Total kW not designated as Firm kW shall constitute Customer's Curtailable kW. Customer's service must be equipped, at Customer's expense, with devices necessary to reduce Total kW during the period of curtailment to Firm kW or below and with metering devices necessary to verify that Total kW is at or below the Firm kW. In addition, the Company may request that the Customer's service be equipped, at Customer's expense, with communication equipment necessary to provide instantaneous load information to Company's designated system operating center.

Company will request curtailment of electric service under this Rider as the Company deems necessary for any reason including, but not limited to, maintaining service to firm loads, avoiding establishment of a new system peak, avoiding establishment of a peak demand in excess of 95% of the Company's forecasted peak load for the year, maintaining service integrity in the area, or other situations when reduction in load on the Company's system is warranted. To the extent possible, curtailable loads served under this Rider will be curtailed before any curtailment of firm loads is requested or required. Requests for curtailment will be made by Company's System Operator via telephonic communication to Customer's designated representative(s). Upon application for service under this Rider, Customer shall designate the representative(s) and provide the telephone number at which they may be reached 24 hours a day. In the event of a curtailment for non-emergency purposes, Company will endeavor to provide notice to Customer at least 30 minutes prior to curtailment. In the event of a curtailment for emergency conditions, Company will attempt to provide as much prior notice as possible but is in no way obligated to give more than 10 minutes notice prior to curtailment. Absence of a designated representative or inability of the Company to communicate with the designated representative because of unanswered telephone, busy telephone, or otherwise, once

Company has initiated a telephonic communication to the designated representative, will in no way be regarded as an excuse for failure to comply with a curtailment request. The Company may request the customer to install at Customer's expense electronic equipment necessary for automatic notification of curtailment.

MONTHLY CHARGES AND CREDITS

Customer's net monthly bill for service provided under this Rider will be calculated in accordance with Company's applicable rate schedule, with the exception that a Curtailable Power Credit will be applied. The Curtailable Power Credit will be determined by applying a Demand Credit to the portion of the average kilowatt load used by the Customer during the 15 minute period of maximum use during the month in excess of the Firm kW. However, the Curtailable Power Credit will not exceed the product of the Demand Credit and the Curtailable kW.

The Demand Credit used to calculate the Monthly Curtailable Power Credit will be:

VOLTAGE LEVEL	**DEMAND CREDIT**
Secondary Service	$3.19/kW
Primary Service	$3.06/kW
Transmission Service	$2.91/kW

NON-COMPLIANCE PROVISIONS

Customer understands that service under this Rider is contingent upon Customer's complete and timely compliance with Company's requests for curtailment. If, at any time, Customer fails in whole or in part to implement or maintain any request for curtailment to reduce the Total kW to

the Firm kW, the Company may, at its option, elect to cancel, effective immediately, the Customer's eligibility for service under this Rider. Should the Company exercise this option, billing for the current and subsequent eleven (11) months will revert to the LP or LLP rate schedule, whichever is applicable. In addition, any Curtailable Power Credits received by the Customer during the 11 previous months shall be forfeited and reimbursed with interest to the Company over the six (6) month period following the cancellation of Customer's eligibility for service under this Rider.

LIMITATIONS ON CURTAILMENTS

Curtailments under this Rider are limited as follows:

Daily Limit: No longer than 12 hours in any day, measured from midnight to midnight, except during system emergencies as described below.

Annual Limit: No more than 400 hours in any calendar year.

The only curtailments included in curtailment time limits are those implemented at the request of Company for the purposes described in the "Conditions of Service" above. Extended interruptions resulting from failure of transmission or distribution equipment are not included in curtailment time limits. Curtailment time is measured from the time the Company notifies the Customer via telephonic communication when the period of curtailment will begin to the time that Company notifies Customer via telephonic communication that the period of curtailment will end.

During system emergencies when Company has made public pleas to restrict electric energy usage to essential needs because of an area or statewide shortage of electric power and/or energy, curtailable loads served under this Rider may be curtailed continuously without daily limit until such emergency condition has ended. Such curtailments shall be included in annual curtailment time limits.

Curtailments of less than 15 minutes in duration shall constitute a 15-minute period for inclusion in Curtailable time limits.

Contract Minimum: The customer's minimum bill shall not be less than the applicable charge for the contracted demand minimum plus the applicable Fuel and Tax Adjustments and in no event shall the contract demand minimum be less than 500 kilowatts.

TERM OF CONTRACT

This Rider is being offered as an experimental service and may be withdrawn by the Company following written notice to each Customer served under the Rider given at least one year prior to such withdrawal. The obligation of the Customer shall continue for a minimum initial term of one year and continuing thereafter unless canceled by Customer following written notice given at least one year prior to such cancellation.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	**Sheet No:** R-37.1	Sheet 1 of 9
Replacing:	**Sheet No:**	
Name of Company: SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	**Class of Service:** As Applicable	
Part III. Rate Schedule No. 37		
Title: UNDERGROUND ELECTRIC DISTRIBUTION SERVICE AGREEMENT		

PSC File Mark Only

I. SCOPE

This policy applies to installation of underground electric distribution systems where feasible from engineering, operation, and economic standpoint to serve. Underground Electric Distribution (UED) and similar phrases include not only electric facilities that are actually located underground, but also above ground which may be necessary to provide service to the customer.

Our basic philosophy, that the developer should pay the cost of underground electric distribution facilities that is in excess of the cost of overhead electric distribution facilities is to be maintained in all instances.

II. DEFINITION OF TERMS

A. For purposes of this policy the following abbreviations and definitions shall prevail:

1. Underground (US) Service -- Customer owned, maintained and installed underground service conductors, sometimes installed in a raceway, that extend from the Customer's meter to the point of delivery, where connection is made to Company's distribution system.

2. Overhead (OH) Service Drop -- Company owned and installed overhead service drop conductors that extend from the Company's overhead distribution

system to the point of delivery, where connection is made to Customer's electrical installation.

3. Point of Delivery -- The point of delivery of electric service shall be the point at which the electrical facilities of the Company connect to the electrical facilities of the Customer.

   a) For Overhead construction, the point of delivery is that point where the Company owned and installed OH Service Drop connects to the Customer owned service entrance wires which are located at the Customer's weatherhead. The Customer owned service entrance wires are connected by the customer to the source side of the meter socket and runs along the customer owned and installed service entrance raceway. The Service Entrance conductors extend out the weatherhead approximately 2 - 3 ft.

   b) For Underground construction, the point of delivery is that point where the Company owned distribution UED secondary facilities connect to the Customer owned and installed UED Service. The customer owned UED service is connected by the customer to the source side of the meter socket and runs underground from the Customer's meter location to the Company owned UED distribution facilities.

4. SWEPCO - Southwestern Electric Power Company.

5. Developer – A person, partnership, association, corporation, or governmental agency that owns, operates, or develops a subdivision or mobile home park.

6. Service Connections – The electrical facilities of the underground system installed, maintained and owned by developer extending from SWEPCO's secondary connection on the distribution system to the point of metering, but not including the meter(s). This would consist of the underground cable from customer's entrance equipment to SWEPCO's secondary pedestal or transformer.

7. Primary - That portion of the distribution system which delivers energy to the primary (high voltage) side of the distribution transformer from the substation or point of supply. Nominal voltages of these primary systems are 2.4 kV, 4Y/2.4 kV, 12.5Y/7.2 kV, and 34.5Y/19.9 kV.

8. Secondary - That portion of the distribution system which distributes the energy from the secondary (low voltage) side of the distribution transformer to the customers' service connection points at utilization voltage. Nominal voltages of these secondary systems are 120/240 volts, 240 volts, 208Y/120 volts, and 480Y/277 volts.

III. CONDITION OF SERVICE

A. UED will be made available in SWEPCO's service area where feasible from engineering, operation, and economic standpoint. The terms and conditions of the Company's Extension of Facilities Agreement (Schedule R-35.1) apply as

ARKANSAS PUBLIC SERVICE COMMISSION

Original **Sheet No:** R-37.4 Sheet 4 of 9

Replacing: **Sheet No:**

Name of Company: SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric **Class of Service:** As Applicable

Part III. Rate Schedule No. 37

Title: UNDERGROUND ELECTRIC DISTRIBUTION SERVICE AGREEMENT

PSC File Mark Only

necessary. The cost estimate for all facilities provided, installed, owned, and maintained by the Company will include:

1. Material cost (purchased and stores);

2. Labor costs (Company and Contract);

3. Transportation cost;

4. Trenching (including backhoeing and boring);

    a) The customer may provide all trenching and backfilling to meet Company specifications.

    b) If the customer provides all trenching and backfilling to meet Company specifications, customer's (CIAC) will be reduced by that amount.

5. Right-of-way clearing, purchase, and acquisition;

6. Permanent Work Orders (PWO’s) (where applicable) and Overheads (exempt material);

7. Stores, Freight, and Handling;

8. Administrative & General costs; and

9. Engineering & Supervisory costs.

B. Differential cost: Customer will pay to Company prior to installation a contribution in aid to construction (CIAC) for all costs in excess of the cost of overhead electric distribution facilities. The CIAC will be grossed up for taxes.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

SOUTHWESTERN ELECTRIC POWER COMPANY

STANDARD AGREEMENT
FOR UNDERGROUND ELECTRIC DISTRIBUTION SYSTEM
BETWEEN

____

____

(Customer, Owner, Developer, Operator, or Builder)
Hereinafter referred to as Customer
AND
SOUTHWESTERN ELECTRIC POWER COMPANY

It is mutually understood and agreed that:

I. This Agreement applies to installation and operation of an underground electric distribution system on easement granted Southwestern Electric Power Company (SWEPCO) on ____

____

____________________________ and is further identified by SWEPCO Drawing No. _____ which is made a part of this Agreement.

II. Electric service covered by this Agreement shall be: (Indicate one)

( ) A. For individually metered customers in residential subdivisions, mobile home parks, apartment complexes, and apartments - single phase, 3 wire

at a nominal voltage of 120/240 volts.

( ) B. For primary metered apartment complexes - primary voltage and phases required are ______________________.

( ) C. For single point service for apartment projects metered at secondary voltage. (Indicate one)

( ) 1. Single phase, 3 wire at a nominal voltage of 120/240.
( ) 2. Three phase, 4 wire at a nominal voltage of 208Y/120.
( ) 3. Three phase, 4 wire at a nominal voltage of 480Y/277.
( ) 4. Three phase, 4 wire at a nominal voltage of 120/240.

III. Service entrance cables shall be installed underground between Customer's building and SWEPCO transformer or secondary service pedestal by Customer.

IV. SWEPCO reserves the right to designate the point of service for each lot, each apartment building, each mobile home space, and each commercial customer.

V. To insure reliability of service to all consumers in an apartment and commercial developments:

A. Customer will provide adequate overcurrent protection to each individual consumer.

ARKANSAS PUBLIC SERVICE COMMISSION

Original **Sheet No:** R-37.8 Sheet 8 of 9

Replacing: **Sheet No:**

Name of Company: SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric **Class of Service:** As Applicable

Part III. Rate Schedule No. 37

Title: UNDERGROUND ELECTRIC DISTRIBUTION SERVICE AGREEMENT

PSC File Mark Only

B. If Customer installs service feeders under a building to centrally located metering points, a spare conduit shall be provided by the Customer to permit rapid restoration of service.

VI. Customer will provide the utility an easement at final grade, the easement shall be clear of trees or other obstructions, as required, with all property corners staked before construction of residential underground electric distribution system begins.

VII. Location of underground facilities, other than the electric distribution system installed by or for the Customer shall be designated by the Customer prior to construction of the electric distribution system.

VIII. Any rearrangements in the electric distribution system or metering arrangement which may be required by the Customer after installation of distribution system shall be paid for by the Customer.

IX. SWEPCO will furnish and install the following equipment:

A. All primary and secondary cables. (Does not include service cable.)
B. Switch enclosures, transformers, transformer enclosures, secondary pedestals, and associated equipment.
C. Any overhead distribution required to provide this service.

X. The Customer will pay the Company the differential cost prior to the installation of (UED) facilities.

ARKANSAS PUBLIC SERVICE COMMISSION

Original **Sheet No:** R-37.9 Sheet 9 of 9

Replacing: **Sheet No:**

Name of Company: SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric **Class of Service:** As Applicable

Part III. Rate Schedule No. 37

Title: UNDERGROUND ELECTRIC DISTRIBUTION SERVICE AGREEMENT

PSC File Mark Only

XI. Customer will pay to the Company at the time of acceptance of the Agreement the sum of $__________ for temporary construction, removal or rearrangement of existing overhead facilities.

XII. Should Customer abandon the use of this underground electric distribution system, he agrees to pay to the Company an amount of money equal to the depreciated value of the system installed, plus the removal cost, less credit for salvage material or equipment.

ACCEPTED ________________________
DATE

WITNESS: ________________________
Customer

________________________ BY ________________________

ACCEPTED ________________________
DATE

WITNESS: SOUTHWESTERN ELECTRIC POWER COMPANY

________________________ BY ________________________
SWEPCO Representative

ATTACHMENT: Drawing No. _________
Work Order No. __________
Rev. 072799

THIS SPACE FOR PSC USE ONLY

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Original	Sheet No. R-38.1 Sheet 1 of 1	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 38		
Title: RECREATIONAL LIGHTING		PSC File Mark Only

AVAILABILITY

This schedule is available for lighting of recreational fields and for miscellaneous recreational facilities to include restrooms and concession stands, where the Customer owns the lighting facilities and the electric service is metered. Non-lighting loads may not exceed 20% of the total lighting load.

Service under this schedule includes but is not limited to facilities with characteristics similar to athletic fields of schools, churches, and public recreational associations.

A written contract may be required at the option of the Company.

TYPE OF SERVICE

The electric service furnished will be to a single metered delivery point and will be at one standard voltage.

This rate schedule is not available for resale, stand-by, or supplemental service.

NET MONTHLY RATE

Customer Charge: $10.60~~8.60~~

Kilowatt-hour Charge: $0.0373~~0257~~ per kilowatt hour

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

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Original	Sheet No. R-39.1 Sheet 1 of 3	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 39		
Title: ALTERNATE FEED SERVICE		PSC File Mark Only

AVAILABILITY

Alternate Feed Service (AFS) may be available for service to customers served under Lighting and Power and Large Lighting and Power Primary Service Schedules, who request an alternate feed service from existing distribution facilities which is in addition to the customer's basic service, provided that the Company can reasonably provide available capacity in existing distribution facilities adjacent to the customers requested delivery point.

NET MONTHLY RATE

In addition to all monthly charges for the customer's basic service as determined under the appropriate Schedule, the customer shall pay the following:

$5.06~~3.95~~	Per kW of AFS billing demand for reserving AFS station and distribution line facilities at primary voltage.

AFS CAPACITY RESERVATION

The customer shall reserve a specific amount of AFS capacity equal to the customer's normal maximum requirements, but in no event shall the customer's AFS reserved capacity under this rider exceed the capacity reservation for the customer's basic service under the appropriate tariff. The Company shall not be required to supply AFS capacity in excess of that reserved except by mutual agreement.

Adjustments:

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider – Arkansas.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-39.2 Sheet 2 of 3	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 39		
Title: ALTERNATE FEED SERVICE		PSC File Mark Only

MEASUREMENT AND DETERMINATION OF DEMAND

The billing demand will be measured and billed in accordance with the tariff requirements set forth in the customer's basic service tariff.

EQUIPMENT AND INSTALLATION CHARGE

The Customer shall be required to pay a one-time equipment and installation charge for all facilities required to provide either a new or upgraded alternate feed service. The equipment and installation charge shall be determined by the Company and shall include, but not be limited to, (a) all cost of the alternate feed facilities, and (b) any cost of modifications to the customer's basic service necessary to install the alternate feed facilities. All equipment shall remain the property of the Company.

TERM

The customer shall contract for a definite amount of electrical capacity in kilowatts which shall be sufficient to meet normal maximum requirements under this Rider, but in no event shall the customer's contract capacity under this Rider exceed the contract capacity for the customer's basic service under the appropriate Schedule. The Company shall not be required to supply capacity in excess of that for which the customer has contracted.

Contracts will be required for an initial period of not less than one (1) year and shall remain in effect thereafter until either party shall give the other at least six (6) months' written notice of the intention to discontinue service under their Rider.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial periods longer than one (1) year pursuant to the Extension of Service provision of the Company's Terms and Conditions of Service.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-39.3 Sheet 3 of 3	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 39		
Title: ALTERNATE FEED SERVICE		PSC File Mark Only

SPECIAL TERMS AND CONDITIONS

The customer shall be responsible for supplying any switching apparatus and facilities which are required in order for the installation to conform to the Company's construction standards and requirements. In those cases where the Company supplies the switching apparatus to conform to the Company's standards and requirements, the customer shall be responsible for the total cost of the switching apparatus, installation, maintenance, and any future replacement costs.

Upon receipt of a request from the customer for non-standard AFS, the Company will provide the customer with a written estimate of all costs, including system impact study costs, and any applicable unique terms and conditions of service related to the provision of the non-standard AFS. The AFS agreement shall provide full disclosure of all rates, terms and conditions of service under this rider, and any and all agreements related thereto.

The Company will have sole responsibility for determining the basic service circuit and the AFS circuit.

Service under this Rider does not guarantee that power will be available through the alternate feed service at all times.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under Company's Standard Terms and Conditions.

TABLE OF CONTENTS

40. NET-METERING

40.1. AVAILABILITY

40.1.1. To any residential or any other customer who takes service under standard rate schedules Residential Service, Electric Heating Appliance Residential Service, General Service, Lighting and Power, Lighting and Power Time-of-Use, Large Lighting and Power, Municipal Service, Municipal Pumping (non-conjunction), and Recreational Lighting who is an owner of a Net-Metering Facility and has obtained a signed Standard Interconnection Agreement for Net-Metering Facilities with the Electric Utility. The generating capacity of Net-Metering Facilities may not exceed the greater of: 1) twenty-five kilowatts (25 kW) or 2) one hundred percent (100%) of the Net-Metering Customer’s highest monthly usage in the previous twelve (12) months for Residential Use. The generating capacity of Net-Metering Facilities may not exceed three hundred kilowatts (300 kW) for non-residential use unless otherwise allowed by the Commission. Net-Metering is intended primarily to offset part or all of the customer’s energy use.

The provisions of the customer’s standard rate schedule are modified as specified herein.

40.1.2. Net-Metering Customers taking service under the provisions of this tariff may not simultaneously take service under the provisions of any other alternative source generation or co-generation tariff except as provided in the Net-Metering Rules.

40.2. MONTHLY BILLING

40.2.1. The Electric Utility shall separately meter, bill, and credit each Net-Metering Facility even if one (1) or more Net-Metering Facilities are under common ownership.

40.2.2. On a monthly basis, the Net-Metering Customer shall be billed the charges applicable under the currently effective standard rate schedule and any appropriate rider schedules. Under Net-Metering, only the kilowatt hour (kWh) units of a Net–Metering Customer's bill are netted.

40.2.3. If the kWhs supplied by the Electric Utility exceeds the kWhs generated by the Net-Metering Facility and fed back to the Electric Utility during the Billing Period, the Net-Metering Customer shall be billed for the net billable kWhs supplied by the Electric Utility in accordance with the rates and charges under the Net-Metering Customer's standard rate schedule.

40.2.4. If the kWhs generated by the Net-Metering Facility and fed back to the Electric Utility during the Billing Period exceed the kWhs supplied by the Electric Utility to the Net-Metering Customer during the applicable Billing Period, the Electric Utility shall credit the Net-Metering Customer with any accumulated Net Excess Generation in the next applicable Billing Period.

40.2.5. Net Excess Generation shall first be credited to the Net-Metering Customer's meter to which the Net-Metering Facility is physically attached (Generation Meter).

40.2.6. After application of 40.2.5 and upon request of the Net-Metering Customer pursuant to 40.2.8, any remaining Net Excess Generation shall be credited to one or more of the Net-Metering Customer's meters (Additional Meters) in the rank order provided by the Net-Metering Customer.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-40.3	Sheet 3 of 16
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 40		
Title: NET-METERING		PSC File Mark Only

40.2.7. Net Excess Generation shall be credited as described in 40.2.5 and 40.2.6 during subsequent Billing Periods; the Net Excess Generation Credits remaining in a Net-Metering Customer's account at the close of a billing cycle shall not expire and shall be carried forward to subsequent billing cycles indefinitely. For Net Excess Generation Credits older than twenty-four (24) months, a Net-Metering Customer may elect to have the Electric Utility purchase the Net Excess Generation Credits in the Net-Metering Customer's account at the Electric Utility's estimated annual average cost rate for wholesale energy if the sum to be paid to the Net-Metering Customer is at least one hundred dollars ($100). An Electric Utility shall purchase at the Electric Utility's estimated annual average Avoided Cost rate for wholesale energy any Net Excess Generation Credits remaining in a Net-Metering Customer's account when the Net-Metering Customer: 1) ceases to be a customer of the Electric Utility; 2) ceases to operate the Net-Metering Facility; or transfers the Net-Metering Facility to another person.

When purchasing Net Excess Generation Credits from a Net-Metering Customer, the Electric Utility shall calculate the payment based on its annual average avoided energy costs in the applicable Regional Transmission Organization for the current year.

40.2.8. Upon request from a Net-Metering Customer the Electric Utility must apply Net Excess Generation to the Net-Metering Customer's Additional Meters provided that:

(a) The Net-Metering Customer must give at least 30 days' notice to the Electric Utility.

(b) The Additional Meter(s) must be identified at the time of the request. Additional Meter(s) shall be under common ownership within a single Electric Utility's service area; shall be used to measure the Net-Metering Customer's requirements for electricity; may be in a different class of service than the Generation Meter; shall be assigned to one, and only one, Generation Meter; shall not be a Generation Meter; and shall not be associated with unmetered service.

(c) In the event that more than one of the Net-Metering Customer's meters is identified, the Net-Metering Customer must designate the rank order for the Additional Meters to which excess kWhs are to be applied. The Net-Metering Customer cannot designate the rank order more than once during the Annual Billing Cycle.

40.2.9. Any Renewable Energy Credit created as the result of electricity supplied by a Net-Metering Customer is the property of the Net-Metering Customer that generated the Renewable Energy Credit.

PRELIMINARY INTERCONNECTION SITE REVIEW REQUEST

Southwestern Electric Power Company – State of Arkansas

I. STANDARD INFORMATION

Section 1. Customer Information

Name: ____

Contact Person: ____

Mailing Address:____

City:______________________ State: ________ Zip Code: __________

Facility Location (if different from above):_______________________

Daytime Phone: _______________ Evening Phone: ________________

E-Mail Address: _____________________Fax: ___________________

If the requested point of interconnection is the same as an existing electric service, provide the electric service account number: _________________________________

Additional Customer Accounts (from electric bill) to be credited with Net Excess Generation: ____

Annual Energy Requirements (kWh) in the previous twelve (12) months for the account physically attached to the Net-Metering Facility and for any additional accounts listed (in the absence of historical data reasonable estimates for the class and character of service may be made):____

Section 2. Generation Facility Information

System Type: Solar Wind Hydro Geothermal Biomass Fuel Cell Micro Turbine (circle one)

Generator Rating (kW): ____________________ AC or DC (circle one)

Expected Capacity Factor: _________________________________

Expected annual production of electrical energy (kWh) of the facility calculated using industry recognized simulation model (PVWatts, etc):_____________________________

Section 3. Interconnection Information

Attach a detailed electrical diagram showing the configuration of all generating facility equipment, including protection and control schemes.

Requested Point of Interconnection: ____

Customer-Site Load (kW) at Net-Metering Facility location (if none, so state):

____

Interconnection Request: Single Phase: ______________ Three Phase: _______________

Section 4. Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Preliminary Interconnection Site Review is true and correct.

Signature: ____________________________________ Date: _____________________

II. TERMS AND CONDITIONS

Section 1. Requirements for Request

For the purpose of requesting that the Electric Utility conduct a preliminary interconnection site review for a proposed Net-Metering Facility pursuant to the requirement of Rule 2.05.B.4, or as otherwise requested by the customer, the customer shall notify the Electric Utility by submitting a completed Preliminary Interconnection Site Review Request. The customer shall submit a separate Preliminary Interconnection Site Review Request for each point of interconnection if information about multiple points of interconnection is requested. Part 1, Standard Information, Sections 1 through 4 of the Preliminary Interconnection Site Review Request must be completed for the notification to be valid. If mailed, the date of notification shall be the third day following the mailing of the Preliminary Interconnection Site Review Request. The Electric Utility shall provide a copy of the Preliminary Interconnection Site Review Request to the customer upon request.

<u>Section 2. Utility Review</u>

Following submission of the Preliminary Interconnection Site Review Request by the customer the Electric Utility shall review the plans of the facility interconnection and provide the results of its review to the customer, in writing, within 30 calendar days. If the customer requests that multiple interconnection site reviews be conducted the Electric Utility shall make reasonable efforts to provide the customer with the results of the review within 30 calendar days. If the Electric Utility cannot meet the deadline it will provide the customer with an estimated date by which it will complete the review. Any items that would prevent Parallel Operation due to violation of safety standards and/or power generation limits shall be explained along with a description of the modifications necessary to remedy the violations.

The preliminary interconnection site review is non-binding and need only include existing data and does not require the Electric Utility to conduct a study or other analysis of the proposed interconnection site in the event that data is not readily available. The Electric Utility shall notify the customer if additional site screening may be required prior to interconnection of the facility. The customer shall be responsible for the actual costs for conducting the preliminary interconnection site review and any subsequent costs associated with site screening that may be required.

<u>Section 3. Application to Exceed 300 kW Net-Metering Facility Size Limit</u>

This Preliminary Interconnection Site Review Request and the results of the Electric Utility's review of the facility interconnection shall be filed with the Commission with the customer's application to exceed the 300 kW facility size limit pursuant to Net Metering Rule 2.05.B.4.

<u>Section 4. Standard Interconnection Agreement</u>

The preliminary interconnection site review does not relieve the customer of the requirement to execute a Standard Interconnection Agreement prior to interconnection of the facility.

STANDARD INTERCONNECTION AGREEMENT FOR NET-METERING FACILITIES

Southwestern Electric Power Company – State of Arkansas

I. STANDARD INFORMATION

Section 1. Customer Information

Name: ____

Mailing Address:______________________________________

City:______________________ State: __________ Zip Code: ____________

Facility Location (if different from above):______________________

Daytime Phone: __________________ Evening Phone: __________________

Utility Customer Account Number (from electric bill) to which the Net-Metering Facility is physically attached: ________________________________

Section 2. Generation Facility Information

System Type: Solar Wind Hydro Geothermal Biomass Fuel Cell Micro turbine (circle one)

Generator Rating (kW): ______________________ AC or DC (circle one)

Describe Location of Accessible and Lockable Disconnect (If required): ____

Inverter Manufacturer: __________________ Inverter Model: ______________

Inverter Location: ______________________ Inverter Power Rating: __________

Expected Capacity Factor: ________________________________

Expected annual production of electrical energy (kWh) calculated using industry recognized simulation model (PVWatts, etc.): ______________________

Section 3. Installation Information

Attach a detailed electrical diagram of the Net-Metering Facility.

Installed by: ____

Qualifications/Credentials: ___________________________________

Mailing Address:______________________________________

City:______________________State: __________ Zip Code:____________

Daytime Phone:__________________ Installation Date:__________________

Section 4. Certification

The system has been installed in compliance with the local Building/Electrical Code of ____(City/County)

Signed (Inspector):__________________________ Date:_______________________

(In lieu of signature of inspector, a copy of the final inspection certificate may be attached.)

The system has been installed to my satisfaction and I have been given system warranty information and an operation manual, and have been instructed in the operation of the system.

Signed (Owner):________________________________ Date:__________________

Section 5. E-mail Addresses for parties

Customer's e-mail address: ____

Utility's e-mail address: __________________________ (To be provided by utility.)

Section 6. Utility Verification and Approval

Facility Interconnection Approved: _________________________ Date: __________

Metering Facility Verification by: ________________ Verification Date: ___________

II. INTERCONNECTION AGREEMENT TERMS AND CONDITIONS

This Interconnection Agreement for Net-Metering Facilities ("Agreement") is made and entered into this _________day of __________, 20_______, by ____________________ __________("Electric Utility") and ____________________________ ("Customer"), a______________(specify whether corporation or other), each hereinafter sometimes referred to individually as "Party" or collectively as the "Parties". In consideration of the mutual covenants set forth herein, the Parties agree as follows:

Section 1. The Net-Metering Facility

The Net-Metering Facility meets the requirements of Ark. Code Ann. § 23-18-603(6) and the Arkansas Public Service Commission's *Net-Metering Rules*.

Section 2. Governing Provisions

The Parties shall be subject to the provisions of Ark. Code Ann. § 23-18-604 and the terms and conditions set forth in this Agreement, the Commission's *Net-Metering Rules*, the Commission's *General Service Rules*, and the Electric Utility's applicable tariffs.

Section 3. Interruption or Reduction of Deliveries

The Electric Utility shall not be obligated to accept and may require Customer to interrupt or reduce deliveries when necessary in order to construct, install, repair, replace, remove, investigate, or inspect any of its equipment or part of its system; or if it reasonably determines that curtailment, interruption, or reduction is necessary because of emergencies, forced outages, force majeure, or compliance with prudent electrical practices. Whenever possible, the Utility shall give the Customer reasonable notice of the possibility that interruption or reduction of deliveries may be required. Notwithstanding any other provision of this Agreement, if at any time the Utility reasonably determines that either the facility may endanger the Electric Utility's personnel or other persons or property, or the continued operation of the Customer's facility may endanger the integrity or safety of the Utility's electric system, the Electric Utility shall have the right to disconnect and lock out the Customer's facility from the Electric Utility's electric system. The Customer's facility shall remain disconnected until such time as the Electric Utility is reasonably satisfied that the conditions referenced in this Section have been corrected.

Section 4. Interconnection

Customer shall deliver the as-available energy to the Electric Utility at the Electric Utility's meter.

Electric Utility shall furnish and install a standard kilowatt hour meter. Customer shall provide and install a meter socket for the Electric Utility's meter and any related interconnection equipment per the Electric Utility's technical requirements, including safety and performance standards.

The customer shall submit a Standard Interconnection Agreement to the Electric Utility at least thirty (30) days prior to the date the customer intends to interconnect the Net-Metering Facilities to the utility's facilities. Part I, Standard Information, Sections 1 through 4 of the Standard Interconnection Agreement must be completed to be valid. The customer shall have all equipment necessary to complete the interconnection prior to such notification. If mailed, the date of notification shall be the third day following the mailing of the Standard Interconnection Agreement. The Electric Utility shall provide a copy of the Standard Interconnection Agreement to the customer upon request.

Following submission of the Standard Interconnection Agreement by the customer, the utility shall review the plans of the facility and provide the results of its review to the customer, in writing, within 30 calendar days. Any items that would prevent Parallel Operation due to violation of applicable safety standards and/or power generation limits shall be explained along with a description of the modifications necessary to remedy the violations.

If the Electric Utility's existing facilities are not adequate to interconnect with the Net-Metering Facility, the Customer shall pay the cost of additional or reconfigured facilities prior to the installation or reconfiguration of the facilities.

To prevent a Net-Metering Customer from back-feeding a de-energized line, the customer shall install a manual disconnect switch with lockout capability that is accessible to utility personnel at all hours. This requirement for a manual disconnect switch will be waived if the following three conditions are met: 1) The inverter equipment must be designed to shut down or disconnect and cannot be manually overridden by the customer upon loss of utility service; 2) The inverter must be warranted by the manufacturer to shut down or disconnect upon loss of utility service; and 3) The inverter must be properly installed and operated, and inspected and/or tested by utility personnel.

Customer, at his own expense, shall meet all safety and performance standards established by local and national electrical codes including the National Electrical Code (NEC), the Institute of Electrical and Electronics Engineers (IEEE), the National Electrical Safety Code (NESC), and Underwriters Laboratories (UL).

Customer, at his own expense, shall meet all safety and performance standards adopted by the utility and filed with and approved by the Commission that are necessary to assure safe and reliable operation of the Net Metering Facility to the utility's system.

Customer shall not commence Parallel Operation of the Net-Metering Facility until the Net Metering Facility has been inspected and approved by the Electric Utility. Such approval shall not be unreasonably withheld or delayed. Notwithstanding the foregoing, the Electric Utility's approval to operate the Customer's Net-Metering Facility in parallel with the Utility's electrical system should not be construed as an endorsement, confirmation, warranty, guarantee, or representation concerning the safety, operating characteristics, durability, or reliability of the Customer's Net-Metering Facility.

Section 5. Modifications or Changes to the Net-Metering Facility Described in Part 1, Section 2

Prior to being made, the Customer shall notify the Electric Utility of, and the Electric Utility shall evaluate, any modifications or changes to the Net-Metering Facility described in Part 1, Standard Information, Section 2 of the Standard Interconnection Agreement for Net-Metering Facilities. The notice provided by the Customer shall provide detailed information describing the modifications or changes to the Utility in writing, including a revised Standard Interconnection Agreement for Net-Metering Facilities that clearly identifies the changes to be made. The Electric Utility shall review the proposed changes to the facility and provide the results of its evaluation to the Customer, in writing, within thirty (30) calendar days of receipt of the Customer's proposal. Any items that would prevent Parallel Operation due to violation of applicable safety standards and/or power generation limits shall be explained along with a description of the modifications necessary to remedy the violations.

If the Customer makes such modification without the Electric Utility's prior written authorization and the execution of a new Standard Interconnection Agreement, the Electric Utility shall have the right to suspend Net-Metering service pursuant to the procedures in Section 6 of the Commission's General Service Rules.

A Net-Metering Facility shall not be modified or changed to generate electrical energy in excess of the amount necessary to offset all of the Net-Metering Customer requirements for electricity.

Section 6. Maintenance and Permits

The customer shall obtain any governmental authorizations and permits required for the construction and operation of the Net-Metering Facility and interconnection facilities. The Customer shall maintain the Net-Metering Facility and interconnection facilities in a safe and reliable manner and in conformance with all applicable laws and regulations.

Section 7. Access to Premises

The Electric Utility may enter the Customer's premises to inspect the Customer's protective devices and read or test the meter. The Electric Utility may disconnect the interconnection facilities without notice if the Electric Utility reasonably believes a hazardous condition exists and such immediate action is necessary to protect persons, or the Electric Utility's facilities, or property of others from damage or interference caused by the Customer's facilities, or lack of properly operating protective devices.

Section 8. Indemnity and Liability

The following is Applicable to Agreements between the Electric Utility and to all Customers except the State of Arkansas and any entities thereof, local governments and federal agencies:

Each Party shall indemnify the other Party, its directors, officers, agents, and employees against all loss, damages, expense and liability to third persons for injury to or death of persons or injury to property caused by the indemnifying party's engineering, design, construction, ownership, maintenance or operations of, or the making of replacements, additions or betterment to, or by failure of, any of such Party's works or facilities used in connection with this Agreement by reason of omission or negligence, whether active or passive. The indemnifying Party shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity. The indemnifying Party shall pay all costs that may be incurred by the other Party in enforcing this indemnity. It is the intent of the Parties hereto that, where negligence is determined to be contributory, principles of comparative negligence will be followed and each Party shall bear the proportionate cost of any loss, damage, expense and liability attributable to that Party’s negligence. Nothing in this paragraph shall be applicable to the Parties in any agreement entered into with the State of Arkansas or any entities thereof, or with local governmental entities or federal agencies. Furthermore, nothing in this Agreement shall be construed to waive the sovereign immunity of the State of Arkansas or any entities thereof. The Arkansas State Claims Commission has exclusive jurisdiction over claims against the state.

Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to or any liability to any person not a Party to this Agreement. Neither the Electric Utility, its officers, agents or employees shall be liable for any claims, demands, costs, losses, causes of action, or any other liability of any nature or kind, arising out of the engineering, design, construction, ownership, maintenance or operation of, or the making of replacements, additions or betterment to, or by failure of, the Customer's facilities by the Customer or any other person or entity.

<u>Section 9.</u> **<u>Notices</u>**

The Net-Metering Customer shall notify the Electric Utility of any changes in the information provided herein.

All written notices shall be directed as follows:

Southwestern Electric Power Company
Attention: Customer Services Manager
P. O. Box 21106
Shreveport, LA 71156

Attention:
[Customer]
Name: ____
Address: ____
City:____

Customer notices to Electric Utility shall refer to the Customer's electric service account number set forth in Section 1 of this Agreement.

<u>Section 10.</u> **<u>Term of Agreement</u>**

The term of this Agreement shall be the same as the term of the otherwise applicable standard rate schedule. This Agreement shall remain in effect until modified or terminated in accordance with its terms or applicable regulations or laws.

<u>Section 11.</u> **<u>Assignment</u>**

This Agreement and all provisions hereof shall inure to and be binding upon the respective Parties hereto, their personal representatives, heirs, successors, and assigns. The Customer shall not assign this Agreement or any part hereof without the prior written consent of the Electric Utility, and such unauthorized assignment may result in termination of this Agreement.

Section 12. Net-Metering Customer Certification

I hereby certify that all of the information provided in this Agreement is true and correct, to the best of my knowledge, and that I have read and understand the Terms and Conditions of this Agreement.

Signature: ______________________________________ Date: ______________________

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized representatives.

Dated this ______________________ day of __________________, 20__.

Customer:	Electric Utility:
_____________________________________	_____________________________________
By: __________________________________	By:__________________________________
Title: ________________________________	Title:_________________________________
Mailing Address: _____________________________________ _____________________________________ _____________________________________	Mailing Address: Southwestern Electric Power Company P. O. Box 21106 Shreveport, LA 71156
E-mail Address: ________________________________	E-mail Address: _________________________________

STANDARD INTERCONNECTION AGREEMENT FOR NET-METERING FACILITIES

Southwestern Electric Power Company – State of Arkansas

Disclaimer

POSSIBLE FUTURE RULES OR RATE CHANGES, OR BOTH AFFECTING YOUR NET-METERING FACILITY

The following is a supplement to the Interconnection Agreement you signed with Southwestern Electric Power Company.

1. Electricity rates, basic charges, and service fees, set by Southwestern Electric Power Company and approved by the Arkansas Public Service Commission (Commission), are subject to change.

2. I understand that I will be responsible for paying any future increases to my electricity rates, basic charges, or service fees from Southwestern Electric Power Company.

3. My Net-Metering System is subject to the current rates of Southwestern Electric Power Company, and the rules and regulations of the Commission. Southwestern Electric Power Company may change its rates in the future with approval of the Commission or the Commission may alter its rules and regulations, or both may happen. If either or both occurs, my system will be subject to those changes.

By signing below, you acknowledge that you have read and understand the above disclaimer.

____
Name (printed)

____
Signature

____
Date

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-41.1 Sheet 1 of 1	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 41		
Title: RESERVED FOR FUTURE USE		PSC File Mark Only

~~**This Schedule has been removed from the tariff book.**~~

Reserved for Future Use

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-42.1 Sheet 1 of 1	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 42		
Title: Radio Frequency Meter Installation Rider		PSC File Mark Only

AVAILABILITY

The Rider for Radio Frequency Meter Installation is available upon request to customers who are served under a rate schedule that requires no more than a single-phase, kWh only meter. A customer may request or elect upon request by the Company to have a radio frequency meter installed under the terms of this Rider as a mutually agreeable solution to Company personnel's lack of meter reading access to Company metering equipment on a customer's premises, due to a locked gate, animal concern, safety concern or other reason.

CONDITION OF SERVICE

The Company will install, own, operate, and maintain the radio frequency meters installed under this Rider. All radio frequency meters installed under this Rider shall remain the property of the Company. After a radio frequency meter is installed, the customer is responsible for keeping the line-of-site clear from obstructions that may impede the reading of the radio frequency meter. The radio frequency meter is not transferable to another location within the Company's service territory to which the customer may move.

Some locations may not be suitable for installation of a radio frequency meter due to possible interference or limitations of the transmitting device. If it is determined by the Company that a location is not suitable for the installation, the radio frequency meter will not be installed and the Company will refund any prior payment received under this Rider.

INSTALLATION FEE

The Radio Frequency Meter Installation Fee is a one-time, non-refundable fee based on the charges as set out below:

For premises requiring a meter exchange	$100.00 per meter
Each additional meter at the same premises	$ 70.00 per meter
For premises requiring new meter installation	$ 53.00 per meter

PAYMENT

The Company will invoice the requesting customer for the total installation fee and will install the radio frequency meter after receipt of payment. The fee is non-refundable after the radio frequency meter is installed.

ARKANSAS PUBLIC SERVICE COMMISSION

Original **Sheet No:** R-43.1 Sheet 1 of 1

Replacing: **Sheet No:**

Name of Company: SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric **Class of Service:** As Applicable

Part III. Rate Schedule No. 43

Title: RESERVED FOR FUTURE USE~~TRANSITION COST RIDER (RIDER TC~~)

PSC File Mark Only

~~This schedule has been removed from the tariff book.~~

Reserved for future use

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-44.1 Sheet 1 of 1	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 44		
Title: PAYMENT FOR SERVICE RIDER (Rules of Practice and Procedure 11.04(b)(10)(B)		PSC File Mark Only

PAYMENT FOR SERVICE

Customers who pay within 22 days of the date of the bill will pay the net bill computed on the Net Monthly Rate. The gross bill will be payable after 22 days of the date of the bill. The gross bill will be the total net bill plus the sum of 10 percent of the first $30 of the net bill plus 2 percent of the amount over $30.

This rider is applicable to the following rate schedules:

2, 3, ~~4,~~ 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, ~~23,~~ 25, 26, 27, 28, 29, 30, 31, 32, 34, 35, 36, 37, 38, 39 ~~43~~.

APSC FILED Time: 2/28/2019 2:15:14 PM: Recvd 2/28/2019 2:14:10 PM: Docket 19-008-U-Doc. 39

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-45.1	Sheet 1 of 5 Including Attachment	
Replacing:	Sheet No.		
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY			
Kind of Service: Electric	Class of Service: All		
Part III. Rate Schedule No. 45			
Title: ENERGY EFFICIENCY COST RECOVERY RIDER (Rider EECR)			PSC File Mark Only

PURPOSE

The purpose of the Energy Efficiency Cost Recovery Rider ("Rider EECR") is to establish the EECR Rate(s) by which Southwestern Electric Power Company (Company) will recover its energy efficiency program costs approved by the Commission in Docket No. 07-082-TF; including, but not limited to: (1) incremental energy efficiency program costs ("Incremental Program Costs"); (2) lost contributions to fixed costs ("LCFC") as described and approved by the Commission in Order No. 14 issued in Docket No 08-137-U; (3) utility incentive as described and approved by the Commission in Order No 15 issued in Docket No. 08-137-U; and (4) a "true-up" adjustment (collectively, the "Recoverable Costs"). Recovery of Incremental Program Costs is limited to the incremental costs which represent the direct program costs that are not already included in the then current rates of the Company. The EECR Rate(s) will be calculated to recover the Company's Recoverable Costs over the period in which the EECR Rate(s) will be in effect.

ANNUAL REDETERMINATION

On or before May 1 of each year, redetermined EECR Rate(s) shall be filed by the Company with the Commission in accordance with the provisions of Section 7 of the Commission's *Rules for Conservation and Energy Efficiency Programs*. The redetermined EECR Rate(s) shall be determined by application of the EECR Rate Formula set out in Attachment A to this Rider EECR. Each such revised EECR Rate shall be filed in Docket No. 07-082-TF and shall be accompanied by supporting testimony and a set of workpapers sufficient to fully document the calculations of the revised EECR Rates(s).

The redetermined EECR Rate(s) shall reflect projected Recoverable Costs for the next calendar year (the "Recoverable Year"); including, but not limited to: (1) the approved incremental Program Costs for the Recoverable Year; (2) the projected LCFC for the Recoverable Year, which shall be inclusive of LCFC for prior reporting years that are not already included within the Company's most recently established base rates; (3) the incentive earned in the prior calendar year (the "Reporting Year"), if any; and (4) a

true-up adjustment reflecting the over-recovery or under-recovery of the EECR Recoverable Costs for the Reporting Year. The true-up adjustment will be calculated to include the effect of carrying costs using the Company's most recently approved rate of return on rate base. The EECR Rate(s) so redetermined shall be effective for bills rendered on and after the first billing cycle of January of the Recoverable Year and shall then remain in effect for twelve (12) months ("EECR Cycle"), except as otherwise provided for below.

INTERIM ADJUSTMENT

Should a cumulative over-recovery or under-recovery balance arise during any EECR Cycle which exceeds ten (10) percent of the EECR Recoverable Costs determined for the EECR Cycle included in the most recently filed rate redetermination under this Rider EECR, then either the Commission General Staff or the Company may propose an interim revision to the then currently effective EECR Rate(s).

TRACKING AND MONITORING PROGRAM COSTS AND BENEFITS

The Company shall develop and implement appropriate accounting procedures, subject to the review of the Commission General Staff, which provide for separate tracking, accounting, and reporting of all program costs incurred by the Company. The procedures shall enable energy efficiency program costs to be readily identified and clearly separated from all other costs. The Company shall secure and retain all documents necessary to verify the validity of the program costs for which it is seeking recovery. Such documents shall include, but not be limited to, vouchers, journal entries, and the date the participant's project was completed.

The Company shall develop and implement appropriate accounting procedures, subject to the review of the Commission General Staff, which provide for separate tracking, accounting, and reporting of

revenues collected through the Rider EECR. The procedures shall enable the EECR revenues to be readily identified and clearly separated from all other revenues. The Company shall secure and retain all documents necessary to verify the accuracy of the EECR revenues. Such documents shall include, but not be limited to, billing determinants, journal entries, and summary revenue reports.

For the purpose of assessing the benefits and effectiveness of the programs, the Company shall develop and implement appropriate procedures, subject to the review of the Commission General Staff, which provide for separate tracking of the benefits and the effectiveness of the programs. The data that shall be tracked shall include, but shall not be limited to, information that will enable the Commission to assess the effectiveness of the programs. The Company shall secure and retain all documents necessary to verify its assessments.

TRACKING AND MONITORING LCFC AND INCENTIVE

The Company shall track and monitor LCFC and Incentives in accordance with Order Nos. 14 and 15, respectively, issued in Docket No. 08-137-U and in future Orders addressing LCFC and Incentives.

TERM

This Rider EECR shall remain in effect until modified or terminated in accordance with the provisions of the Rider EECR or applicable regulations or laws.

If this Rider EECR is terminated by a future order of the Commission, the EECR Rate(s) then in effect shall continue to be applied until the Commission approves an alternative mechanism by which the Company can recover its energy efficiency costs. At that time, any cumulative over-recovery or under-recovery resulting from application of the just terminated EECR Rate(s) shall be applied to customer billings over the twelve (12) month billing period beginning on the first billing cycle of the second month following the termination of Rider EECR in a manner prescribed by the Commission.

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ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-45.4	Sheet 4 of 5 Including Attachment	
Replacing:	Sheet No.		
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY			
Kind of Service: Electric	Class of Service: All		
Part III. Rate Schedule No. 45			
Title: ENERGY EFFICIENCY COST RECOVERY RIDER (Rider EECR)			PSC File Mark Only

APPLICABLE RATE SCHEDULES

Residential Class:
Residential,
Residential, Electric Heating Appliance Residential Service,
Commercial/Industrial Class:
General Service,
Lighting & Power Service – Secondary,
Lighting & Power Service – Primary,
Lighting & Power TOU – Primary,
Lighting & Power TOU – Secondary;
Large Lighting & Power – Primary,
Large Lighting & Power – Transmission,
Pulp and Paper Mill – Transmission,
Supplemental, Backup, Maintenance, and As-Available Standby Power Service,
Recreational Lighting
Municipal Class:
Municipal Pumping Service,
Municipal Service;
Lighting Class:
Municipal Street & Parkway Lighting,
Public Street & Highway Lighting,
Private Lighting,
Area Lighting.

The appropriate EECR rate will be applicable to any new rate schedule approved by the Commission.

Southwestern Electric Power Company
Energy Efficiency Cost Recovery Rider (Rider EECR)
ATTACHMENT A

	Total Recoverable Costs	Residential	Commercial/ Small Industrial	Industrial	Municipal	Lighting
2006-2007 Ark. Energy Efficiency Expenses	18,600					
Education Iniatitive	82,000					
Ark. Weatherization Program	188,800					
Energy Star Appliance Program	100,500					
Compact Fluorescent Lighting	89,000					
Commercial/Industrial Standard Offer	287,400					
Emergency Load Management (loadshare)	180,300					
1 **Total of All Programs**	$ 946,600					
2 Allocator (1)	100.0%	27.9840%	52.1359%	18.4416%	0.5591%	0.8794%
3 Allocated Current Recoverable	$ 946,600	$ 264,896	$ 493,519	$ 174,568	$ 5,292	$ 8,325
4 Prior Period Over/Under, includes carrying costs	$ -	$ -	$ -	$ -	$ -	$ -
5 Total Recoverable Amount	$ 946,600	$ 264,896	$ 493,519	$ 174,568	$ 5,292	$ 8,325
6 Billing Units - kWh (Nov 07-Dec 08)	5,137,316,385	1,337,668,450	2,793,727,850	936,300,640	22,124,184	47,495,261
7 EECR Rate ($/kWh)	$ 0.00018	$ 0.00020	$ 0.00018	$ 0.00019	$ 0.00024	$ 0.00018

(1) Demand and Energy Allocator from Cost Of Service study (June 1998)

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-46.1 Sheet 1 of 4	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 46		
Title: FEDERAL LITIGATION CONSULTING FEE RIDER		PSC File Mark Only

1. PURPOSE

The Federal Litigation Consulting Fee Rider defines the procedures by which the Federal Litigation Consulting Fee Rate shall be determined. The Federal Litigation Consulting Fee Rate shall recover the fees and expenses paid by Southwestern Electric Power Company ("Company") to contract attorneys and consultants retained by the Arkansas Public Service Commission (Commission), as authorized by the General Assembly, when it participates in litigation before a federal agency or federal court in proceedings which affect the Company. See Ark. Code Ann. §23-4-102.

2. APPLICATION

The Federal Litigation Consulting Fee Rate is applicable to all electric service billed under the rate schedules designated in Attachment A to this Rider. The Net Monthly Rates of the Company's currently effective rate schedules will be adjusted by the Federal Litigation Consulting Fee Rate amount set forth in Attachment A to this Rider, which shall apply during the period indicated thereon. The Federal Litigation Consulting Fee Rate amounts shall be revised pursuant to the procedures described in Section 6 below.

3. BILL REVIEW AND PAYMENT

When involved in federal litigation, bills for litigation consulting fees and expenses shall be submitted by the contracting attorney(s) and/or consultant(s) to the Commission on a monthly basis. After review and approval by the Commission, the Commission will forward the bills for the approved fees and expenses to the Company Designees listed in Section 4 below. The maximum amount that may be directly recovered shall not exceed $3,000,000 annually.

The Company shall remit payment for the Federal Litigation Consulting Fees directly to the contracting party within thirty (30) days of the bill's receipt by the Company. A record of the payments will be maintained in an appropriate, separate account.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-46.2 Sheet 2 of 4	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 46		
Title: FEDERAL LITIGATION CONSULTING FEE RIDER		PSC File Mark Only

4. COMPANY DESIGNEES

Lynn Ferry-Nelson~~Johnie Wise~~
Director Regulatory Services
SWEPCO
P.O. Box 21106
Shreveport, La 71156

Elizabeth Stephens
Regulatory Consultant
SWEPCO
P.O. Box 21106
Shreveport, LA 71156

5. ANNUAL RATE REVISIONS

5.1 Annual Filing Requirements
On or before February 15 of any year following a calendar year in which Federal Litigation Consulting Fees are paid, the Company may file for recovery of the Federal Litigation Consulting Fees. The Federal Litigation Consulting Fees Rate shall be calculated annually in accordance with the provisions of Paragraph 6.1 and filed for approval with the Commission.

Once a docket is established, annual revisions shall be filed in the same docket each year thereafter. Each Federal Litigation Consulting Fee rate filing shall be accompanied by a set of workpapers sufficient to fully document the timely payment of the third party contract fees and expenses, the accounting treatment for such payments, and the calculation of the rate.

6. CALCULATION AND RECOVERY PROCEDURES

6.1 Federal Litigation Consulting Fee Rate Calculation
The Federal Litigation Consulting Fee rate shall include the Commission-approved contract fees and expenses paid in the preceding calendar year. The rate shall not include any interest or carrying charges. The Federal Litigation Consulting Fee rate shall be determined by dividing the federal litigation consulting fees and expenses paid by the projected energy sales for the twelve-month period commencing on April 1 of each year. This rate shall also include a true-up adjustment reflecting the over-recovery or under-recovery of the federal litigation consulting fees for the preceding calendar year.

The Federal Litigation Consulting Fee rate so determined shall be effective, after Commission approval, for bills rendered on and after the first billing cycle of April of the filing year and shall then remain in effect until the last billing cycle of March of the following year, or other billing period as approved by the Commission.

Should there be unusual circumstances either the Company or the Staff may propose to modify the above calculation.

6.2 Federal Litigation Consulting Fee Rate Recovery
The Federal Litigation Consulting Fee rate, once approved by the Commission, shall be applied to each customer's monthly billing energy (kWh). The rate shall be constant across all customer classes and applied to the currently effective rate schedules. The Federal Litigation Consulting Fee Rate shall be set forth in Attachment A to this Rider and shall be filed with the utilities' tariffs.

6.3 Federal Litigation Consulting Fee Rate True-up
At the time of the annual filing, the actual recovery of Federal Litigation Consulting Fees will be compared to the projected recovery for the preceding calendar year. Any net over-recovery or under-recovery of the Federal Litigation Consulting Fees shall be included in setting the Federal Litigation Consulting Fee rate for the next recovery period.

Southwestern Electric Power Company
Federal Litigation Consulting Fee Rate
ATTACHMENT A

The Net Monthly rates for all customers shall be adjusted by the following amount for recovery of the Federal Litigation Consulting Fee from the first billing cycle of (month) 20XX through the last billing cycle of (month) 20XX.

$x.xxxxxx per kWh

Applicable Rate Schedules

Residential Service,
Residential, Electric Heating Appliance Residential Service,
~~Residential – Rider to Residential Service for Controlled Service to Water Heaters;~~
General Service,
Lighting & Power Service – Secondary,
Lighting & Power Service – Primary,
~~C-1 Heating Rider,~~
Lighting & Power TOU – Primary,
Lighting & Power TOU – Secondary;
Large Lighting & Power – Primary,
Large Lighting & Power – Transmission,
Pulp and Paper Mill – Transmission
Supplemental, Backup, Maintenance, and As-Available Standby Power Service
Municipal Pumping Service,
Municipal Service;
Municipal Street & Parkway Lighting,
Public Street & Highway Lighting,
Private Lighting,
Area Lighting,
Recreational Lighting.

The Federal Litigation Consulting Fee Rider shall apply to all kilowatt-hours billed during each monthly billing cycle. For electric service billed under applicable rate schedules for which there is no metering, the Company shall estimate the monthly kWh usage and the Federal Litigation Consulting Fee Rider shall be applied.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-47.1 Sheet 1 of 5	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 47		
Title: RESERVED FOR FUTURE USE~~ALTERNATIVE GENERATION RECOVERY (GR) RIDER~~		PSC File Mark Only

This Schedule has been removed from the tariff book.

Reserved for Future Use

~~**PURPOSE**~~

~~This Generation Recovery (GR) Rider is designed to adjust monthly billings to recover costs associated with the Stall generating facility that has received a certificate of environmental compatibility and public need issued by the Arkansas Public Service Commission (APSC). The GR Rider is designed to recover return on and of the generation facility and operation and maintenance expenditures after the facility commences commercial operation.~~

~~This schedule is applicable to and becomes part of each APSC jurisdictional rate schedule. This schedule is applicable to energy consumption of retail customers and to facilities, premises and loads of such retail customers.~~

~~The GR Factors will include the Arkansas' jurisdictional portion of the Stall generation facilities once it is placed in commercial operation. The Arkansas jurisdictional portion will be determined using the most recently approved production allocation factors for SWEPCO Arkansas. The GR factors will be calculated in accordance with the following methodology and will be applied as a percentage of base rates to all classes with the exception of the Residential class where it will be applied to each kWh sold.~~

~~**GR FACTORS**~~

~~The Generation Recovery Factors (GR Factors) shall be set forth in Attachment A to this GR Rider.~~

THIS SPACE FOR PSC USE ONLY

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-47.2	Sheet 2 of 5
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 47		
Title: RESERVED FOR FUTURE USE~~ALTERNATIVE GENERATION RECOVERY (GR) RIDER~~		PSC File Mark Only

~~ANNUAL DETERMINATION~~

~~The initial period for the GR Factors shall be the forecasted initial 12 months of operation after the commercial operation date of the generation facility.~~

~~A True-up Adjustment shall be calculated and reflected in the following year's GR Factor calculation. The True-up Adjustment shall be defined as the difference between the actual GR costs for the prior year and the revenue received from the GR Factors.~~

~~GR factors shall be filed by the Company with the Commission and shall be accompanied by a set of workpapers sufficient to fully document the calculations of the GR Factors including any potential True-up Adjustment.~~

~~The GR factors shall be calculated as shown below:~~

~~GR = ((GENP – ADEP)*ROR + DEPX + O&M) * RBAF + TU/ Forecasted Base Revenues or kWh Sales by Major Rate Class, as appropriate.~~

~~GENP = Average generation plant in service balance for the forecasted calendar year for the Arkansas Jurisdiction.~~

~~ADEP = Average accumulated depreciation balance for the forecasted calendar year for the Arkansas jurisdiction based on the production depreciation rate in effect for the Arkansas Jurisdiction.~~

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. R-47.3 Sheet 3 of 5

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: All

Part III. Rate Schedule No. 47

Title: RESERVED FOR FUTURE USE~~ALTERNATIVE GENERATION RECOVERY (GR) RIDER~~

PSC File Mark Only

~~DEPX = Depreciation expense for the forecast period based on the depreciation rates in effect for the Arkansas Jurisdiction.~~

~~O&M = Operations and Maintenance expense for the forecasted period for the Arkansas Jurisdiction.~~

~~ROR = Return on plant in service which includes interest on debt, shareholder return and related income taxes based on a pre-tax rate of return specific to the GR Rider of 8.14%, with the weighted equity component rate grossed-up by the gross conversion factor specific to income taxes, as approved by the Commission in Docket No 09-008-U.~~

~~RBAF = Production Demand Allocation Factor for each major rate class from the Company's cost allocation study provided in the most recent rate case, Docket No. 09-008-U. The allocation factors may be adjusted subject to Commission approval, when necessary, to accommodate significant customer shifts between classes. The allocators are as follows:~~

~~Major Rate Class~~	~~Production Allocators~~
~~Residential~~	~~33.62%~~
~~Commercial and Small Industrial~~	~~50.44%~~
~~Large Industrial~~	~~15.06%~~
~~Municipal~~	~~0.35%~~
~~Lighting~~	~~0.53%~~

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-47.4	Sheet 4 of 5
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 47		
Title: RESERVED FOR FUTURE USE~~ALTERNATIVE GENERATION RECOVERY (GR) RIDER~~		PSC File Mark Only

~~TU = The true-up amount to correct for any variance between the actual GR costs for the prior year and the revenue received from the GR factors. The calculation will be done on an annual basis, and will determine the true-up for the following year.~~

~~STAFF AND COMMISSION REVIEW~~

~~The Company will file with the Commission the requested GR Annual Factors approximately 90 days preceding the requested effective date. Staff shall review the filed GR factors to verify that the formula has been correctly applied and shall notify the Company of any necessary corrections. After the Staff completes its review of the rate calculation, the Company shall make appropriate changes to correct undisputed errors identified by the Staff in its review. Any disputed issues arising out of the Staff review are to be resolved by the Commission after notice and hearing. The requested GR Factors will become effective, upon Commission approval, with the first billing cycle of the requested billing month or the first billing cycle of the month subsequent to the approval.~~

~~TERM~~

~~The GR Factors will remain in effect for 12 months and will expire unless a request for updated GR Factors is filed by the Company or until updated GR Factors are approved by order of the Commission or until the generating facility is included in retail base rates of the Company~~

~~If this GR rider is terminated by a future order of the Commission, the GR Factors shall continue to be in effect until such costs are recovered through another mechanism or until the implementation of new base rates reflecting such costs.~~

~~Collections under the GR Rider are subject to refund, with interest, after notice and hearing to determine prudence.~~

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ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. R-47.5 Sheet 5 of 5

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: All

Part III. Rate Schedule No. 47

Title: RESERVED FOR FUTURE USE~~ALTERNATIVE GENERATION RECOVERY (GR) RIDER~~

PSC File Mark Only

~~ATTACHMENT A~~

~~GR FACTORS~~

~~All base retail rates and applicable riders on file with the APSC will be increased or decreased by the factors listed below.~~

~~Major Rate Class~~	~~Applicable Factors~~	
~~Residential~~	~~$0.00271~~	~~per kWh~~
~~Commercial and Small Industrial~~	~~7.79%~~	~~of base rate revenue~~
~~Large Industrial~~	~~11.35%~~	~~of base rate revenue~~
~~Municipal~~	~~4.30%~~	~~of base rate revenue~~
~~Lighting~~	~~1.10%~~	~~of base rate revenue~~

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ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. R-48.1 Sheet 1 of 2

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: All

Part III. Rate Schedule No. 48

Title: RESERVED FOR FUTURE USE~~ENVIRONMENTAL COMPLIANCE SURCHARGE RIDER (RIDER ECS)~~

PSC File Mark Only

This Schedule has been removed from the tariff book.

Reserved for Future Use

~~PURPOSE~~

~~This Environmental Compliance Surcharge Rider (Rider ECS) is designed to adjust monthly billings to recover costs associated with government mandated expenditures related to the protection of the public health, safety, and the environment pursuant to the provisions of Act 310 of 1981, as amended.~~

~~This schedule is applicable to and becomes part of each APSC jurisdictional rate schedule. This schedule is applicable to energy consumption of retail customers and to facilities, premises and loads of such retail customers.~~

~~The ECS Factors will include the Arkansas jurisdictional portion of eligible facilities. The Arkansas jurisdictional portion will be determined using jurisdictional allocation factors for SWEPCO Arkansas from SWEPCO's most recent base rate case in Arkansas. The ECS Factors will be applied to each kWh sold for all major rate classes.~~

~~TERM~~

~~The ECS Factors are effective on and after March 30, 2017. Collections under the ECS Rider are subject to refund, with interest, after notice and hearing to determine reasonableness. The ECS Factors will remain in effect until a request for updated ECS Factors is filed by the Company or until updated ECS Factors are approved by order of the Commission or until the facilities are included in retail base rates of the Company. Revised rates will be filed no more frequently than once every six months.~~

THIS SPACE FOR PSC USE ONLY

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. R-48.2 Sheet 2 of 2

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: All

Part III. Rate Schedule No. 48

Title: RESERVED FOR FUTURE USE~~ENVIRONMENTAL COMPLIANCE SURCHARGE RIDER (RIDER ECS)~~

PSC File Mark Only

~~The inclusion of any costs via this surcharge shall not be deemed a finding that the costs are necessary and appropriate or in the public interest. The prudency of such costs shall be addressed in the Company's next general rate case proceeding. If any costs via this surcharge are not found prudent in the Company's next general rate case proceeding, then the applicable surcharge collections will be refunded with interest.~~

~~ECS FACTORS~~

~~The ECS Factors below will be applied to each kWh sold for each major rate class:~~

~~Major Rate Class~~	~~Applicable Factors~~
~~Residential~~	~~$ 0.00449 per kWh~~
~~Commercial and Small Industrial~~	~~$ 0.00342 per kWh~~
~~Large Industrial~~	~~$ 0.00314 per kWh~~
~~Municipal~~	~~$ 0.00354 per kWh~~
~~Lighting~~	~~$ 0.00201 per kWh~~

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-49.1	Sheet 1 of 2
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 49		
Title: RESERVED FOR FUTURE USE~~FEDERAL TAX CUT ADJUSTMENT RIDER (RIDER FTCA)~~		PSC File Mark Only

This Schedule has been removed from the tariff book.

Reserved for Future Use

~~PURPOSE~~

~~The purpose of this rider is to provide retail customers with certain tax benefits associated with the Tax Cuts and Jobs Act of 2017 (TCJA). The TCJA reduces the maximum corporate income tax rate from 35 percent to 21 percent beginning January 1, 2018. The Federal Tax Cut Adjustment Rider (Rider FTCA) flows back to customers excess income tax and Accumulated Deferred Income Tax (ADIT) currently included in the Company's base rates approved in Docket No. 09-008-U and the Company's most recent Environmental Compliance Surcharge Rider approved in Docket No. 15-021-U.~~

~~APPLICATION~~

~~This schedule is applicable to and becomes part of each APSC jurisdictional rate schedule. This schedule is applicable to base revenue of retail customers and to facilities, premises and loads of such retail customers. The FTCA Factors will include the Arkansas jurisdictional portion of the refund amount and will apply to base revenue for all major rate classes.~~

~~FTCA FACTORS~~

~~Beginning with the October 2018 billing month through the December 2019 billing month, all retail base rates on file with the APSC will be decreased by the factors listed below.~~

~~Major Rate Class~~	~~Applicable Factors~~
~~Residential~~	~~-20.17 % of base revenue~~
~~Commercial and Small Industrial~~	~~-22.53 % of base revenue~~
~~Large Industrial~~	~~-25.98 % of base revenue~~
~~Municipal~~	~~-15.87 % of base revenue~~
~~Lighting~~	~~-18.69 % of base revenue~~

ARKANSAS PUBLIC SERVICE COMMISSION

Original | Sheet No. R-49.2 | Sheet 2 of 2

Replacing: | Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric | Class of Service: All

Part III. Rate Schedule No. 49

Title: RESERVED FOR FUTURE USE~~FEDERAL TAX CUT ADJUSTMENT RIDER (RIDER FTCA)~~

PSC File Mark Only

~~Beginning with the January 2020 billing month, all retail base rates on file with the APSC will be decreased by the factors listed below until such time that new base rates become effective.~~

~~Major Rate Class~~	~~Applicable Factors~~
~~Residential~~	~~-6.76 % of base revenue~~
~~Commercial and Small Industrial~~	~~-7.67 % of base revenue~~
~~Large Industrial~~	~~-9.17 % of base revenue~~
~~Municipal~~	~~-5.44 % of base revenue~~
~~Lighting~~	~~-6.30 % of base revenue~~

~~TRUE-UP~~

~~On or before February 1, 2020, the Company will file a true-up calculation to reconcile any estimated tax refund amounts to actual tax amounts refunded. The true-up filing will include the final Unprotected and Protected excess ADIT amounts based upon its 2017 income tax return compared to the amounts actually returned to customers from October 2018 through December 2019. Any over- or under- returned excess ADIT would then be credited or billed to customers during the billing month of March 2020.~~

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-50.1	Sheet 1 of 23 Including Attachments	
Replacing:	Sheet No.		
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY			
Kind of Service: Electric	Class of Service: All		
Part III. Rate Schedule No. 50			
Title: FORMULA RATE REVIEW (FRR) RIDER			PSC File Mark Only

REGULATORY AUTHORITY

The Arkansas General Assembly has delegated authority to the Arkansas Public Service Commission ("APSC" or the "Commission") to regulate public utilities in the State of Arkansas, including Southwestern Electric Power Company ("SWEPCO" or the "Company"). The Arkansas General Assembly has enacted the Formula Rate Review Act, Ark. Code Ann. §§ 23-4-1201 *et seq.*, which authorizes use of this Formula Rate Review ("FRR") Rider.

PURPOSE

The FRR defines the procedure by which all rates and applicable riders (Rate Schedules) on file with the APSC, except those excluded in Attachment A.1 to this FRR, may be periodically adjusted. The FRR shall apply to all electric service billed under the Rate Schedules, whether metered or unmetered.

DEFINITIONS

EFFECTIVE DATE -

Rates pursuant to the initial FRR shall become effective with the first billing cycle of October 2021 and subsequently adjusted FRR rates shall be effective with the first billing cycle of each successive projected year.

FORMULA RATE REVIEW TEST PERIOD -

The Formula Rate Review Test Period shall be a test period based upon a Historical Year. A Historical Year shall be the twelve (12) month period ending December 31 of the year preceding the filing of an Evaluation Report.

ANNUAL FILING AND REVIEW

ANNUAL FILING

On or about April 1, 2021 and on or about April 1 of each subsequent year during the term of the FRR, SWEPCO shall file a report ("Evaluation Report") with the Commission containing an evaluation of the Company's earnings pursuant to the FRR for the Historical Year. Attachment A-1 shall be included in each such filing and shall contain the Company's proposed Rate Adjustment. The Evaluation Report and the Rate Adjustment shall be filed pursuant to the FRR.

REVIEW PERIOD

The Parties shall file a statement of error(s) or objection(s) and supporting Testimony with or without Exhibits at least 90 days before the date on which the Rate Adjustment becomes effective. The Company shall have fifteen (15) days to review the statement of error(s) or objection(s), to work with the Parties to resolve any differences, and to address the error(s) and objection(s) raised by the Parties by filing either a corrected Attachment A.1 or Rebuttal Testimony with or without Exhibits.

HEARING AND APPROVAL OF RATE ADJUSTMENT

Following a hearing at least fifty (50) days before the date on which the Rate Adjustment shall become effective, unless waived by SWEPCO and the Parties, the Commission shall issue a final order in which it resolves any issues in dispute and approves the Rate Adjustment at least twenty (20) days before the date on which the Rate Adjustment shall become effective. If a final order is not issued by such date, the initially filed or revised Rate Adjustment shall become effective for bills rendered on and after the first billing cycle of October, subject to refund, and shall remain in effect until changed by final order of the Commission or by operation of other provisions of this FRR.

If the Commission's final ruling on any disputed issues requires changes to the Rate Adjustment, the Company shall file a revised Attachment A-1 containing such further modified Rate Adjustment within five (5) days after receiving the Commission's order resolving the disputed issues. The Parties shall have three (3) days to review the revised Attachment A-1. The revised Attachment A-1 shall be implemented as ordered by the Commission.

FRR BANDWIDTH CALCULATION

The Total FRR revenue level shall be adjusted in the FRR review mechanism based on a comparison of the ERR to the TRR calculated using the following formula:

A. If the ERR is less than the TRR minus five-tenths percent (0.50%), the Total FRR Revenue level shall be increased by the amount necessary to increase the ERR to the TRR.

B. If the ERR is greater than the TRR plus five-tenths percent (0.50%), the Total FRR Revenue level shall be decreased by the amount necessary to decrease the ERR to the TRR.

C. There shall be no change to the FRR Revenue level if the ERR is less than or equal to the TRR plus five-tenths percent (0.50%), and greater than or equal to the TRR minus five-tenths percent (0.50%).

FRR REVENUE ALLOCATION

The total change in the formula rate revenue level shall be allocated to each applicable rate class based on an equal percentage of the base rate revenue used in the development of rates approved by the Commission in Docket No. 19-008-U. The total amount of such revenue increase or decrease for each rate class shall not exceed four percent (4%) of the revenue for each rate class for the Filing Year.

TERM

The initial term of the FRR rider shall not exceed five (5) years from the date of the Commission's final order in Docket No. 19-008-U. If SWEPCO requests an extension of the FRR rider, SWEPCO shall make such request in accordance with the Extension of Term provisions of the Formula Rate Protocols.

If the FRR is not extended, the then-existing Total FRR rates shall continue to be in effect until new base rates are duly approved and implemented.

ARKANSAS PUBLIC SERVICE COMMISSION

ANNUAL DETERMINATION OF RATE ADJUSTMENT

INDEX OF ATTACHMENTS

Attachment	Description
A-1	FRR Rate Adjustment (Rate Adjustment).
A-2	FRR Revenue Change and includes the calculation of the total FRR Revenue to be collected in the Projected Year.
B-1	Earned Rate of Return ("ERR") on Common Equity. The ERR is the Company's return on common equity calculated by dividing the weighted earned common equity rate by the common equity ratio percentage.
B-2	Rate Base
B-3	Operating Income
B-4	Income Tax
B-5	Benchmark Rate of Return on Rate Base ("BRORB"). The BRORB is the composite weighted, embedded cost of capital reflecting SWEPCO's annual costs of long-term debt, preferred stock, common equity, and other capital components as of the Test Year end.
B-6	Revenue Redetermination Formula using the Rate of Return on Common Equity Bandwidth which is an Upper Bandwidth limit equal to the Target Return Rate (TRR) plus 0.5% (50 basis points) and a Lower Bandwidth limit equal to the TRR minus 0.5% (50 basis points). The TRR is the Company's cost rate for common equity as established by the Commission in Docket No. 19-008-U.
C	FRR Plan Adjustments
D	FRR Filing Requirements and description of the supporting documents to be included with the annual Evaluation Report.
E	Formula Rate Review Protocols which include the FRR general provisions and filing requirements for the annual Evaluation Report.

Attachment A-1

SOUTHWESTERN ELECTRIC POWER COMPANY
FORMULA RATE REVIEW
RATE ADJUSTMENT

All retail base rates and applicable riders on file with the APSC will be increased or decreased by a percentage of base revenues listed below, except those specifically excluded below:

Rate Class	FRR Rate (%)
Residential	XX.XXXX%
Commercial / Small Industrial	XX.XXXX%
Large Industrial	XX.XXXX%
Municipal	XX.XXXX%
Lighting	XX.XXXX%

Excluded Schedules: Energy Cost Recovery Rider (ECR)
Energy Efficiency Cost Recovery Rider (EECR)
Distribution Reliability Rider (DR Rider)

Attachment A-2

SOUTHWESTERN ELECTRIC POWER COMPANY
FORMULA RATE REVIEW
FRR RIDER REVENUE CHANGE

Line A	Description B	Total C	Residential D	Commercial / Small Industrial E	Large Industrial F	Municipal G	Lighting H
1	Base Rate Revenue: Docket No. XX-XXX-X	$	$	$	$	$	$
2	Rate Class Allocation: (Percent of Total from Line 1)	%	%	%	%	%	%
3	**FRR Constraint Calculation [1]**						
4	Total Annualized Filing Year Revenues by Rate Class	$	$	$	$	$	$
5	FRR Revenue Change ± 4% per Rate Class		4.00%	4.00%	4.00%	4.00%	4.00%
6	Upper FRR Revenue Constraint		$	$	$	$	$
7	Lower FRR Revenue Constraint		-$	-$	-$	-$	-$
9	**Calculated FRR Increase**						
10	ROE Bandwidth Rate Adjustment [2] (B-6, L 10 * L 2)	$	$	$	$	$	$
11	Incremental FRR Base Rate Change L10 ÷ (L1 + L13)	%	%	%	%	%	%
12	**Cumulative FRR Revenue Calculation [3]**						
13	Maximum Inc / Dec in FRR Revenue calculated on L9 bounded by the constraint defined on L6 and L7	$	$	$	$	$	$
14	Annualized Filing Year FRR Rider Revenue [4]	$	$	$	$	$	$
15	Cumulative Total FRR Rider Revenue (L13 + L14)	$	$	$	$	$	$
16	**Rider FRR Rate Development Calculation [5]**						
17	Adjusted Historical Base Rate Revenue (B-3, L 2)	$	$	$	$	$	$
18	FRR Rate Change (L15 ÷ L17)	%	%	%	%	%	%

NOTES:

[1] The FRR constraint calculation determines the limit of the FRR revenue increase/decrease per rate class, which shall not exceed four percent (4%) of Total Unadjusted Annualized Revenues.

[2] The Net Change in Required FRR Revenue Calculation takes the Total Historical Year Rate Change in Rider FRR Revenue (B-6, L10) and allocates the amount to each rate class based on the class allocation approved by the Commission in Docket No. 19-008-U listed on line 2.

[3] The Cumulative Rider FRR revenue calculation adjusts the required Rider FRR revenue determined on Line 10 to be within the limits of the Rider FRR constraint calculation and adds the Annualized Filing Year FRR Rider Revenue to calculate the Cumulative Total FRR Rider Revenue.

[4] The Annualized Filing Year FRR Rider Revenue in the initial Filing Year of 20XX will be zero ($0). In subsequent Filing Years, the Annualized Filing Year FRR Revenue shall reflect the annualized effect using the historical test year billing data of the FRR Rate Adjustment in effect at the end of the test year under this FRR Rider.

[5] The Rider FRR Rate Development Calculation determines the percent increase/decrease that will be applied to all base rate components. The Adjusted Historical Year Base Rate Revenue is calculated using the Retail Rate Schedule Revenue (B-3, L2) excluding Historical Year FRR Revenue and any revenue pursuant to excluded schedules on Attachment A-1. The percent increase/decrease is calculated by taking the Cumulative Total FRR Rider Revenue (L15) and dividing it by the Adjusted Historical Year Base Rate Revenue (L17).

SOUTHWESTERN ELECTRIC POWER COMPANY
FORMULA RATE REVIEW
EARNED RATE OF RETURN ON COMMON EQUITY FORMULA
Test Year Ending MMM/DD/YYYY

LINE NO	(1) DESCRIPTION	(2) REFERENCE	(3) AMOUNT
	ARKANSAS RETAIL		
1	RATE BASE	B-2, L 25, Col. 6	$
2	BENCHMARK RATE OF RETURN ON RATE BASE	B-5, L 12, Col. 5	%
3	REQUIRED OPERATING INCOME	L1 * L 2	$
4	NET UTILITY OPERATING INCOME	B-3, L 36, Col. 6	$
5	OPERATING INCOME DEFICIENCY/(EXCESS)	L 3 - L 4	$
6	REVENUE CONVERSION FACTOR (A)	Note [1]	#
7	REVENUE DEFICIENCY/(EXCESS)	L5 * L6	$
8	PRESENT RETAIL BASE RATE REVENUES	B-3, L 2, Col. 6	$
9	REVENUE REQUIREMENT	L7 + L8	$
10	COMMON EQUITY DEFICIENCY/(EXCESS) (%)	L7 / L6 / L1	%
11	WEIGHTED TEST YEAR RATE OF RETURN ON COMMON EQUITY (%)	B-5, L 3, Col. 6	%
12	WEIGHTED CALCULATED COMMON EQUITY RATE (%)	L11 - L10	%
13	COMMON EQUITY RATIO (%)	B-5, L 3, Col. 3	%
14	EARNED RATE OF RETURN ON COMMON EQUITY (%)	L12 / L13	%

NOTE:

[1] REVENUE CONVERSION FACTOR = 1 / [(1-COMPOSITE TAX RATE) * (1-FACTORING RATE) * (1-FRANCHISE TAX RATE)]

Combined Tax Rate		%
Factoring Rate		%
Franchise Tax Rate		%
Federal Rate		%
State Rate		%
Combined Tax Rate		%

SOUTHWESTERN ELECTRIC POWER COMPANY
FORMULA RATE REVIEW
ARKANSAS
RATE BASE
Test Year Ending MMM/DD/YYYY

LINE NO	(1) DESCRIPTION	(2) TOTAL CO PER BOOKS	(3) TOTAL CO ADJUSTMENTS [1]	(4) TOTAL CO ADJUSTED AMOUNT	(5) APSC RETAIL ALLOCATION FACTOR (D)	(6) APSC ADJUSTED AMOUNT
1	PLANT IN SERVICE					
2	Beginning Balance	$	$	$	%	$
3	Ending Balance	$	$	$	%	$
4	Average Balance	$	$	$	%	$
5	ACCUMULATED DEPRECIATION					
6	Beginning Balance	$	$	$	%	$
7	Ending Balance	$	$	$	%	$
8	Average Balance	$	$	$	%	$
9	AVERAGE NET UTILITY PLANT (L4 + L8)					$
10	PLANT ACQUISITION ADJUSTMENT					
11	Beginning Balance	$	$	$	%	$
12	Ending Balance	$	$	$	%	$
13	Average Balance	$	$	$	%	$
14	AMORTIZATION OF ACQUISITION ADJUSTMENT					
15	Beginning Balance	$	$	$	%	$
16	Ending Balance	$	$	$	%	$
17	Average Balance	$	$	$	%	$
18	WORKING CAPITAL ASSETS					
19	MATERIALS AND SUPPLIES	$	$	$	%	$
20	PREPAYMENTS	$	$	$	%	$
21	FUEL INVENTORY	$	$	$	%	$
22	WORKING CASH	$	$	$	%	$
23	TOTAL WORKING CAPITAL ASSETS	$	$	$	%	$
24	OTHER	$	$	$	%	$
25	TOTAL RATE BASE (L9+L13+L17+L23+L24)					$

NOTES:
[1] Adjustments as set forth in Attachment C to this Rider FRR.

THIS SPACE FOR PSC USE ONLY

Docket No. 19-008-U
Order No. XX
Effective: XX/XX/201X
Rate Schedule No. 50

SOUTHWESTERN ELECTRIC POWER COMPANY
FORMULA RATE REVIEW
ARKANSAS
OPERATING INCOME
Test Year Ending MMM/DD/YYYY

LINE NO	(1) DESCRIPTION	(2) TOTAL CO PER BOOKS	(3) TOTAL CO ADJUSTMENTS [1]	(4) TOTAL CO ADJUSTED AMOUNT	(5) APSC RETAIL ALLOCATION FACTOR	(6) APSC ADJUSTED AMOUNT
	REVENUES					
1	SALES TO ULTIMATE CUSTOMERS					
2	APSC RETAIL	$	$	$	%	$
3	LPSC RETAIL	$	$	$	%	$
4	PUCT RETAIL	$	$	$	%	$
5	TOTAL (Sum of L2 - L4)	$	$	$		$
6	SALES FOR RESALE	$	$	$	%	$
7	SYSTEM SALES	$	$	$	%	$
8	OTHER ELECTRIC REVENUE	$	$	$	%	$
9	TOTAL OPERATING REVENUES (Sum of L5 - L8)	$	$	$		$
	EXPENSES					
10	OPERATION & MAINTENANCE					
11	PRODUCTION	$	$	$	%	$
12	TRANSMISSION	$	$	$	%	$
13	REGIONAL MARKET	$	$	$	%	$
14	DISTRIBUTION	$	$	$	%	$
15	CUSTOMER ACCOUNTING	$	$	$	%	$
16	CUSTOMER SERVICE & INFORMATION	$	$	$	%	$
17	SALES	$	$	$	%	$
18	ADMINISTRATIVE & GENERAL	$	$	$	%	$
19	TOTAL O&M EXPENSE (Sum of L11 - L18)	$	$	$		$
20	GAIN FROM DISPOSITION OF PLANT/ALLOWANCE	$	$	$	%	$
21	REGULATORY DEBITS AND CREDITS	$	$	$	%	$
22	DEPRECIATION & AMORTIZATION EXPENSE	$	$	$	%	$
23	ACCRETION EXPENSE	$	$	$	%	$
24	AMORTIZATION OF PLANT ACQUISITION ADJ	$	$	$	%	$
25	FACTORING EXPENSE	$	$	$	%	$
26	OTHER CREDIT FEES	$	$	$	%	$
27	TAXES OTHER THAN INCOME	$	$	$	%	$
28	CURRENT STATE INCOME TAX [2]	$	$	$	%	$
29	CURRENT FEDERAL INCOME TAX [2]	$	$	$	%	$
30	DEF STATE INC TAX - NET [3]	$	$	$	%	$
31	DEF FEDERAL INC TAX - NET [3]	$	$	$	%	$
32	INVESTMENT TAX CREDIT	$	$	$	%	$
33	GAIN/LOSS - DISPOSITION OF UTILITY PLANT	$	$	$	%	$
34	OTHER (D)	$	$	$	%	$
35	TOTAL OPERATING EXP (Sum of L19 to L34)	$	$	$		$
36	NET UTILITY OPERATING INCOME (L9 - L35)	$	$	$	%	$

Notes
[1] Adjustments as set out in Attachment C to this Rider FRR.
[2] Reference Attachment B-4. See also Filing Requirement Item No. 15, MFR C-11 for additional support.
[3] See supporting schedule of calculation of adjustments and descriptions. See Filing Requirement Item No. 15, MFR C-9 & C-12.

SOUTHWESTERN ELECTRIC POWER COMPANY
FORMULA RATE REVIEW
ARKANSAS
INCOME TAX EXPENSE
Test Year Ending MMM/DD/YYYY

LINE NO	(1) DESCRIPTION	(2) TOTAL CO PER BOOKS	(3) TOTAL CO ADJUSTMENTS [1]	(4) TOTAL CO ADJUSTED AMOUNT	(5) ASPSC RETAIL ALLOCATION FACTOR	(6) APSC ADJUSTED AMOUNT
1	TOTAL OPERATING REVENUE	$	$	$	%	$
2	TOTAL O&M EXPENSE	$	$	$	%	$
3	GAIN FROM DISPOSITION OF PLANT/ALLOWANCES	$	$	$	%	$
4	REGULATORY DEBITS AND CREDITS	$	$	$	%	$
5	DEPRECIATION & AMORTIZATION EXPENSE	$	$	$	%	$
6	ACCRETION EXPENSE	$	$	$	%	$
7	AMORTIZATION OF PLANT ACQUISITION ADJ	$	$	$	%	$
8	FACTORING EXPENSE	$	$	$	%	$
9	OTHER CREDIT FEES	$	$	$	%	$
10	TAXES OTHER THAN INCOME	$	$	$	%	$
11	GAIN/LOSS - DISPOSITION OF UTILITY PLANT	$	$	$	%	$
12	OTHER	$	$	$	%	$
13	INTEREST EXPENSE [2]					
14	NET INCOME BEFORE INCOME TAXES (L1-sum(L2 to L13))			$		$
15	ADJUSTMENTS TO NET INCOME BEFORE INCOME TAX [3]	$	$	$	%	$
16	TAXABLE INCOME (L14 + L15)	$	$	$	%	$
	COMPUTATION OF STATE INCOME TAX					
17	TAXABLE INCOME (L16)	$	$	$	%	$
18	STATE ADJUSTMENTS [3]	$	$	$	%	$
19	STATE TAXABLE INCOME (L17 + L18)	$	$	$	%	$
20	STATE INCOME TAX BEFORE ADJUSTMENTS (L19 * Tax Rate) [1]	$	$	$	%	$
21	ADJUSTMENTS TO STATE INCOME TAX [3]	$	$	$	%	$
22	**STATE INCOME TAX (L20 + L21)**	$	$	$	%	$
	COMPUTATION OF FEDERAL INCOME TAX					
23	TAXABLE INCOME (L16)	$	$	$	%	$
24	STATE INCOME TAX BEFORE ADJUSTMENTS (L20)	$	$	$	%	$
25	FEDERAL ADJUSTMENTS [3]	$	$	$	%	$
26	TOTAL FEDERAL TAXABLE INCOME (L23 - L24 + L25)	$	$	$	%	$
27	FEDERAL INCOME TAX BEFORE ADJUSTMENTS (L26 * Tax Rate) [	$	$	$	%	$
28	ADJUSTMENTS TO FEDERAL TAX [3]	$	$	$	%	$
29	**FEDERAL INCOME TAX (L27 + L28)**	$	$	$	%	$

Notes
[1] Adjustments and applicable tax rates as set forth in Attachment C to this Rider FRR.
[2] Interest Expense for is Weighted Cost of Debt (COD) Rate as derived from COD elements reflected in Attachment B-5 times Rate Base per Attachment B-2.
[3] List all adjustments including descriptions in a supporting schedule. See Filing Requirement Item No. 15, MFR C-11 for additional support.

THIS SPACE FOR PSC USE ONLY

Docket No. 19-008-U
Order No. XX
Effective: XX/XX/201X
Rate Schedule No. 50

SOUTHWESTERN ELECTRIC POWER COMPANY
FORMULA RATE REVIEW
ARKANSAS
BENCHMARK RATE OF RETURN ON RATE BASE
Test Year Ending MMM/DD/YYYY

	(1)	(2)	(3)	(4)	(5)
LINE NO	DESCRIPTION	CAPITAL AMOUNT ($) [1]	CAPITAL RATIO (%)[2]	COST RATE (%)[3]	BENCHMARK RATE OF RETURN ON RATE BASE [4]
1	Long-Term Debt	$	%	%	%
2	Preferred Stock	$	%	%	%
3	Common Equity	$	%	%	%
4	Accumulated Deferred Income Tax	$	%	%	%
5	Pre-1971 ADITC	$	%	%	%
6	Post-1970 ADITC	$	%	%	%
7	Customer Deposits	$	%	%	%
8	Short-Term / Interim Capital	$	%	%	%
9	Current Accrued, and Other Liabilities	$	%	%	%
10	Capital Leases	$	%	%	%
11	Other Capital Items	$	%	%	%
12	TOTAL	$	%	%	%

NOTES:

[1] The capital balances for Long-Term Debt, Capital Leases, Preferred Stock, Common Equity, and ADIT shall be Test Year Ending balances consistent with Commission Order in Docket No. 19-008-U. Short-Term Debt balances and CAOL balances shall be based on the 13-month averages ending as of the Test Year end and include all accounts consistent with those ordered by the Commission in Docket No. 19-008-U. All other capital components including customer deposits shall be determined as of the Test Year end. Support for the 13 month average Short-Term debt shall be provided. Support for the CAOL balances shall include the same format and detail as required by the Filing Requirements in Attachment E, Item No. 15. A Test Year ending balance sheet should be provided as well as a reconciliation between the balance sheet and Column (2) amounts.

[2] Capital amounts each divided by the Total Capital Amount.

[3] The cost rates shall be calculated in accordance with the calculation applied by the Commission in Docket No.19-008-U. Support for the cost of Long-Term Debt and cost of Preferred Stock shall be provided in the same format and level of detail required by the Filing Requirements, respectively. Support for the Short-Term debt cost rate should include a general description of how the interest rae is determined and the same level of detail provided in the Filing Requirements in Attachment E, Item No. 15. The cost rate for Customer Deposits shall be the Commission-approved rate in effect during the year. The cost rate for Common Equity shall be that approved by Commission Order In Docket No. 19-008-U.

[4] The components in Column (5) are the corresponding Cost Rates multiplied by the associated Capital Ratio.

SOUTHWESTERN ELECTRIC POWER COMPANY
FORMULA RATE REVIEW
ARKANSAS
FRR REVENUE REDETERMINATION FORMULA
Test Year Ending MMM/DD/YYYY

SECTION 1

BANDWIDTH DEVELOPMENT

	DESCRIPTION	REFERENCE	
1	Earned Rate of Return on Common Equity ("ERR") [1]	B-1 , L 14	%
2	Target Rate of Return ("TRR") [2]	B-5, L 3, Col. 4	%
3	Upper Bandwidth Limit	Line 2 + 0.05%	%
4	Lower Bandwidth Limit	Line 2 - 0.05%	%
5	ROE Adjustment	If L1 < L4, then L2 - L1; If L1 > L3, then L2 - L1, but no adjustment if L1 ≥ L4 or L1 ≤ L3	%

SECTION 2

ROE BANDWIDTH RATE ADJUSTMENT

	DESCRIPTION	REFERENCE	
6	ROE Adjustment	per Line 5	%
7	Common Equity Capital Ratio	B-5, L 3, Col. 3	%
8	Retail Rate Base	B-1, L 1, Col. 3	$
9	Revenue Conversion Factor	B-1, L 6, Col. 3	#
10	Total Rate Change in FRR Revenue	L6 * L7 * L8 * L9	$

Notes:

[1] The ERR is the Earned Rate of Return on Common Equity calculated by dividing the weighted earned common equity rate by the common equity ratio percentage.

[2] The TRR is SWEPCO's cost rate for common equity as established by the Commission in Docket No. 19-008-U.

Attachment C
Southwestern Electric Power Company
FORMULA RATE REVIEW ADJUSTMENTS

The actual (per book) data for each Test Year reflected in Attachment B shall be adjusted to reflect the following specific ratemaking adjustments to rate base, operating income, and rate of return:

I. General

A) SWEPCO shall not record a regulatory asset or a regulatory liability representing the amount by which an FRR increase or decrease absent the operation of the 4 percent cap exceeds the actual FRR increase or decrease that is implemented pursuant to the operation of this tariff.

B) During the term of the FRR the Lost Contribution to Fixed Costs portion of the Company's Energy Efficiency Rider shall be set to zero after any true-ups, if needed, for timing purposes.

C) If not specifically mentioned in this Attachment C, revenues, expenses, cost of capital components and any other cost effects shall be treated in the same manner as in Docket No. 19-008-U.

D) Rate base amounts for the Test Year shall exclude construction work in progress (CWIP), Non-Utility Plant, and Plant Held for Future Use.

E) The Arkansas Jurisdictional Revenue Requirement will be determined by running the total company historical costs through the approved Cost of Service model from Docket 19-008-U. The Company will provide a fully-functioning cost of service model able to replicate the Company's determination of the jurisdictional revenue requirement, containing links to the supporting accounting schedules which contains the level of detail (e.g., subaccounts or detailed plant information) commensurate with the detail required by the cost of service model.

F) Plant additions requiring either CECPN or CCN approvals (generation and transmission plant) in any SWEPCO jurisdiction shall be included in this FRR, but related revenues recovered under this FRR shall be subject to refund pending a prudence review in the next general rate case, if the prudence determination doesn't occur during the FRR review. All other plant additions shall be deemed prudent once included in this FRR.

II. Cost of Service Ratemaking Adjustments

A. Rate Base

1. Use Test Year-end balances for Electric Plant In Service (EPIS) and Accumulated Depreciation on a total company basis excluding the Turk Generation Power Station and related Generator Step-up Transformers.

2. Use 13-month averages ending December 31 of the Test Year for working capital assets, excluding amounts (e.g., non-jurisdictional) and accounts consistent with Docket No. 19-008-U.

3. Restate balances of accumulated depreciation (and related depreciation ADIT) using existing Arkansas depreciation rates in effect when the depreciation expense was incurred.. During an annual FRR filing,

a utility may request an interim rate for plant added which has no approved depreciation rate, excluding major plant acquisitions. Depreciation rates for major plant acquisitions must be requested within the docket requesting approval of the purchase.

4. Remove from Test Year Rate Base all non-Arkansas jurisdictional, non-utility amounts and other items consistent with Docket No. 19-008-U.

5. Include AFUDC adjustment to EPIS, accumulated depreciation and ADIT computed consistent with Docket No. 19-008-U including Arkansas' approved return on common equity and the FERC AFUDC formula.

6. Eliminate rate base effects associated with any riders other than this FRR Rider that SWEPCO may have in effect during the test year that recover specific costs.

B. Operating Income

1. The Test Year shall reflect actual revenues. No adjustments for rate annualization, growth or weather shall be included.

2. The revenue and expense effects associated with any riders other than this Rider FRR that SWEPCO may have in effect during the test year that recover specific costs are to be eliminated.

3. Include other revenues consistent with the methodology utilized in Docket No. 19-008-U.

4. Do not annualize or normalize test year revenues or expenses, except for depreciation expense which shall be restated using approved depreciation rates and changes in EPIS.

5. Include credit line fees in operating expenses that are not included in cost of debt or recovered elsewhere in the cost of service.

6. Specifically assign jurisdictional other taxes in same manner as SWEPCO filed its revenue requirement as in Docket No. 19-008-U.

7. Exclude other costs not recognized for ratemaking, including, but not limited to, the Turk Generation Power Station, charitable contributions, lobbying expenses, fines and penalties, and disallowances consistent with Docket No. 19-008-U.

8. Adjust federal and state income expense, and deferred tax expense, for the following:
   i. All Historical Year interest expenses shall be eliminated and replaced with an imputed interest expense amount equal to the rate base multiplied by the weighted embedded cost of debt;
   ii. Effects associated with other adjustments set out in this Attachment C shall similarly and consistently be adjusted;
   iii. The corporate state and federal income tax laws legally in effect at test year end shall be reflected in the calculation of all income tax amounts; and any changes in the statutory federal income tax rate will be treated as a direct flowthrough item in the year the new tax rate is effective as long as the flowthrough complies with normalization rules; and,
   iv. Tax effects normally excluded in prior Commission Orders regarding SWEPCO for ratemaking purposes shall be eliminated.

C. Benchmark Rate of Return on Rate Base

1. Short-term Debt shall be included consistent with Docket No. 19-008-U.

2. All Long-Term Debt issues as of the Test Year end, including current maturities, shall reflect the balance net of a) unamortized debt discount, premium, and issuance expense and b) the gains or losses on reacquired debt should be included as a component of total net outstanding Long-Term, consistent with Docket No. 19-008-U.

3. All Preferred Stock issues as of the Test Year end shall reflect the balance net of discount, premium and capital stock expense, consistent with Docket No. 19-008-U.

4. Accumulated Deferred Income Taxes (ADIT) will be treated as zero-cost capital reflecting balances at Test Year-End. ADIT shall include all accounts consistent with those approved in Docket No. 19-008-U. Any associated excess ADIT recorded in the Company's Regulatory Assets/Liabilities receives the same ADIT treatment consistent with Docket No. 19-008-U.

5. CAOL shall be based on the 13-month averages ending as of the Test Year end, and include all accounts consistent with those ordered by the Commission in Docket No. 19-008-U.

6. All other capital components including customer deposits shall be determined as of the Test Year end.

7. The cost rates to be applied for Long-Term Debt and Preferred Equity shall be determined as of the Test Year end. The Long-Term Debt cost rates shall include the a) annual amortization of debt discount premium and expenses; and b) annual gain or loss on reacquired debt.

8. The cost rate to be applied for Common Equity shall be the authorized Rate of Return on Common Equity approved by the Commission in Docket No. 19-008-U.

9. The cost rates for ADIT and CAOL will be zero.

10. The cost rates for other capital items including customer deposits, short-term debt and other capital components will be determined as of the Test Year end and calculated in a consistent manner with Docket No. 19-008-U.

Attachment D

SOUTHWESTERN ELECTRIC POWER COMPANY
FORMULA RATE REVIEW
FILING REQUIREMENTS

Item No.	Filing Requirements
1	SWEPCO shall file all FRR Attachments supporting the Test Year. For the initial FRR application, SWEPCO shall provide the FERC FORM Number 1 for the test year and the four preceding years. The FERC FORM Number 1 for the test year will be provided when filed at the FERC.
The following information shall be provided to the Parties:	
2	In support of the Test Year FRR schedules, the Company will provide a fully-functioning cost of service model as approved by the Commission in Docket 19-008-U. The Cost of Service model should be able to replicate the Company's determination of the jurisdictional revenue requirement, containing links to the supporitng accounting schedules which contains the level of detail (e.g., subaccounts or detailed plant information) commensurate with the detail required by the cost of service model. Total company amounts shall be reconciled to the Trial Balances provided in item 3.
3	Monthly Trial Balances by detail general ledger subaccount number for the Test Year.
4	Identify all construction projects or purchases that closed to plant during the Test Year greater than $1 million on a total basis. Include the project number, project description, start date, completion date, date closed to plant, cost to complete, and plant accounts where it was closed. Provide the costs, including the AFUDC calculation, included in the five (5) largest projects completed during the year.
5	Rules of Practice and Procedure, Appendix 8-1 Minimum Filing Requirements (MFR) Schedules, as modified for the Test Year, B-1, B-2, B-4, B-5, B-10, C-2, C-4, C-5, C-8, C-9, C-10, C-11, C-12, D-2, D-3, D-5, D-6.1, D-6.2, D-6.3, D-7, F-1, G-1, G-2, G-3 and G-4, including the supporting cost of service study (Jurisdictional Only). For the F-1 Schedule, provide a reconciliation to Schedule B-1 and the plant amounts in the monthly trial balance (item 3 above).
6	Detailed chart of accounts, including subaccounts and detailed description (i.e. MFR E-9). List of project codes, activity codes, resource codes and detailed description for each.
7	Web access to SWEPCO's general ledger for the Test Year including capablility to view supporting invoices.
8	For the Test Year, by rate class and rate schedule, provide a monthly statement showing customer count, kWh, coincident and non-coincident kW demands, base rate revenues, and rider revenues.
9	For the 12 month's prior to the Test Year, provide actual revenues by rate class.
10	SWEPCO/AEPSC internal and external audit reports for the Test Year and any proposed auditor's adjustments to be filed confidentially.
11	The most recently filed State and Federal Income Tax Returns for SWEPCO and AEP to be filed confidentially. Also provide any return that becomes available during the discovery period related to the Test Year.

Attachment E

FORMULA RATE REVIEW PROTOCOLS
Section I. General Provisions

1. Applicability and Scope

A. The following protocols shall apply to the annual Evaluation Report filings made pursuant to the Formula Rate Review (FRR) Rider approved by the Commission in Docket No. 19-008-U.

B. The Rules of Practice and Procedure (RPPs) shall apply to all annual Evaluation Report filings, except the following for which the Commission has granted an exemption by approving the FRR:

Rule 3.08;
Rule 4.02 (a)(2)(A);
Rule 4.02 (a)(3);
Rule 4.02 (a)(4);
Rule 4.03 (c);
Rule 4.04 (a)(2);
Rule 4.10 (a)(2) & (3); and
Rule 5.05(b), (c), & (d).

C. Any proposed modification of the FRR Rider, including these protocols, is outside the scope of an annual Evaluation Report filing and as such, no Party shall seek to modify the FRR Tariff, including these protocols, as part of any annual Evaluation Report filing. Proposed modifications to the FRR Tariff, including these protocols, shall be brought in a separate docket.

D. The filing of an annual Evaluation Report is a Formal Application. The filings of an annual Evaluation Report are not to be construed as a General Rate Change Application, nor are adjustments to rates that result from the filings of an annual Evaluation Report to be construed as a general change in rates pursuant to any provision of the Arkansas Code that references a general change in rates.

E. The Commission may grant an exemption from compliance with these Protocols if the exemption is found to be in the public interest and for good cause shown.

2. Public Notice

A. At least thirty (30) days prior to filing an annual Evaluation Report, SWEPCO shall give public notice of its intent to file.

B. The notice shall indicate that it is from SWEPCO and shall include: the docket number, if known; the date on or about which the annual Evaluation Report is to be filed; the effective date of FRR rates; reference to the RPPs and these protocols for persons interested in intervening, making a limited appearance, or submitting public comments in writing or orally at the hearing; deadlines for intervention as provided herein; the name, address, phone number and email address of the Secretary of the Commission and the URL address of the Commission website; and that further information may be obtained by contacting the Secretary of the Commission or viewing the Commission's website.

C. Public notice shall be given by any method including but not limited to: bill notation, direct mail, email exploder list, publication on SWEPCO's website, through social media, or publication in a newspaper of general circulation in SWEPCO's service area.

D. An annual Evaluation Report filing shall include a declaration that these notice provisions have been complied with.

3. Intervention

A. A Petition to Intervene shall be filed within ten (10) calendar days from the date the annual Evaluation Report is filed.

B. Any Party desiring to file a Response to a Petition to Intervene shall file the Response within five (5) calendar days of the filing of the Petition. No additional responses or replies shall be permitted unless specifically authorized by the Commission.

C. The Commission shall rule on the Petition to Interveners within seven (7) calendar days from the date the Petition is filed. If the Commission does not rule within that time frame, the Petition to Intervene shall be deemed denied.

4. Discovery

A. Time Within Which to Respond or Object

1. The Party upon whom discovery is sought shall serve a written response or objection within ten (10) calendar days after service of the discovery. Responses or objections to requests for admission shall be served within ten (10) calendar days of service of the requests. The Commission may prescribe a shorter or longer time. Any objections shall state the specific reasons for such objection.

2. If the response to the discovery request contains protected information for which no Protective Order has been issued, the responsive Party shall apply for a Protective Order as soon as reasonably practicable after receipt of the discovery request so as to avoid any delays in responding to discovery, and to the greatest extent practicable no later than five (5) calendar days after receipt of the discovery request. SWEPCO shall respond to the discovery request on the next business day after the Protective Order is issued or on the date the discovery response is due.

B. Discovery Initiation

Unless otherwise ordered, a Party may initiate discovery at any time after filling of an annual Evaluation Report so long as responses or objections and depositions shall be completed at least sixty (60) days before the date on which rates determined by the formula rate review mechanism will go into effect for each year or ten (10) days before a hearing on the merits, whichever is earlier.

C. Service and Format

1. Service shall be made by electronic mail, facsimile transmission, hand delivery, or overnight delivery service unless unusual circumstances otherwise justify delivery by another method and the Parties agree to the method chosen.

2. Attachments to documents shall be provided in native electronic format, with formulae and viable links intact.

3. Any discovery document served electronically or by facsimile after Commission Business Hours but before midnight or received on a non-business day shall be deemed served on Persons on the Official Service List with electronic mail on the next business day. Any discovery document served electronically or by facsimile between midnight and the beginning of Commission Business Hours on a business day shall be deemed served on Persons on the Official Service List on that business day. Any discovery document served by hand delivery or overnight delivery service shall be deemed served pursuant to Rule 3.07 of the RPPs.

D. Computation of Time for Performance or Response

In computing the time within which an act must be performed or a response made, the Day of the act from which the designated period of time begins to run shall not be included and the last Day shall be included unless it is a Saturday, Sunday, Legal Holiday, or other Day in which the Commission's office is closed, in which event the period shall extend to the next business Day. Service by mail or commercial delivery service is prohibited; therefore no additional response time as contemplated by the RPPs is necessary.

5. General Filing Matters

A. Beginning with the initial annual Evaluation Report filing after the FRR is approved by the Commission in Docket No. 19-008-U, a separate docket shall be established by the Secretary of the Commission for the annual Evaluation Report filings with an "FR" docket designation.

B. The initial and all subsequent annual Evaluation Reports filed in the "FR" docket. SWEPCO shall submit the annual Evaluation Report with a Commission-approved tariff Docket Summary Cover Sheet. In addition to any other information required by the coversheet, SWEPCO shall reference Docket No. 19-008-U.

C. Stipulations or Settlements

1. Parties shall propose by written motion that the Commission adopt stipulations or settlements. Such motion shall be filed, along with supporting testimony, no later than seven (7) calendar days prior to the hearing scheduled in the annual Evaluation Report filing. If the seventh day falls on a weekend or state holiday such settlement agreement and supporting testimony shall be filed on the last business day prior to the seventh day. The motion shall set forth the factual, legal, policy, and other consideration which form the basis for the Parties' recommendation that the stipulation or agreement be adopted, and shall be supported by written testimony.

2. A Party not joining a proposed stipulation or settlement may file a response no later than five (5) calendar days prior to the scheduled date of the hearing.

3. Such a response shall set forth the factual, legal, policy, and other consideration which form the basis for the Party's opposition to the proposed stipulation or settlement or portions thereof.

Section II. Filing Requirements

1. Testimony and Exhibits

A. Testimony with or without Exhibits shall be filed simultaneously with the annual Evaluation Report and address, at a minimum:

1. A description of the filed schedules and all of the adjustments proposed;

2. A description of any significant cost drivers;

3. A description of any changes in accounting policies, practices, and procedures if they affect inputs to the FRR or the rate redetermination to be made under the FRR; and

4. A narrative explanation of the rate impact.

2. Workpapers and Supporting Documentation

A. The annual Evaluation Report and any revisions thereto shall include:

1. Data-populated schedules including fully functioning EXCEL spreadsheet with all formulas and links intact, showing all calculations in the annual Evaluation Report;

2. Sufficient information to enable the Parties to replicate the calculation of the formula results from the applicable schedules; and

3. Documentation fully supporting all calculations and adjustments.

B. Workpapers shall be provided to the Parties simultaneously with the filing of the annual Evaluation Report and any revisions thereto, and shall include:

1. All supporting calculations and documents that explain the calculations in the annual Evaluation Report;

2. Both references to and support from detailed source information; and

3. A complete description of any statistical model used, the data used, and the results of the analysis if not addressed in testimony or exhibits.

C. With respect to any change in accounting that affects inputs to the FRR or the resulting rate redetermination to be billed under the FRR, SWEPCO shall identify and provide narrative explanation of the individual impact of such changes on rate redetermination to be billed under the FRR including:

1. The initial implementation of an accounting standard or policy;

2. The initial implementation of accounting practices for unusual or unconventional items where the Commission has not provided specific accounting direction;

3. Correction of errors and prior period adjustments that impact the FRR;

4. The implementation of new estimation methods or policies that change prior estimates; and

5. Changes to income tax elections.

D. SWEPCO shall identify any reorganization or merger transaction and explain the effect of the accounting for such transaction(s) on the inputs to the FRR or the resulting rate determination to be billed under the FRR.

3. Waiver of Requirements

SWEPCO may omit specific items of information from the annual Evaluation Report filing only with prior Commission approval.

4. Filing Deficiencies

A. The Arkansas Public Service Commission General Staff ("Staff") may review each annual Evaluation Report filing to ascertain whether it complies with the provisions of these Filing Requirements and the FRR, including the provisions of all of the Attachments thereto.

B. If Staff determines that any deficiencies exist, Staff shall file a notice detailing the deficiencies within seven (7) calendar days from the date the annual Evaluation Report is filed.

C. SWEPCO shall correct the deficiencies, within seven (7) calendar days of filing of the notification of deficiency, or upon objection being filed by SWEPCO within that timeframe; the Commission may set a longer period as may be reasonable.

D. Staff shall review corrections made by SWEPCO to determine compliance with all information required by the Filing Requirements and the FRR, including the provisions of all of the Attachments thereto.

E. No more than three (3) business days from the filing of corrections, Staff may file a (1) statement of compliance or (2) a second notice of deficiencies, listing each requirement not met and a brief explanation in support.

F. The Commission shall resolve any dispute as to deficiencies within seven (7) calendar days of the filing of the second notice of deficiencies by either accepting the corrections made by SWEPCO or by directing additional corrections to be filed by SWEPCO.

5. Dispute Procedures

A. Any Party filing with the Commission a statement of errors or objections to the Evaluation Report shall file Testimony with or without Exhibits simultaneously with the statement of errors or objections and the filing shall:

1. Clearly identify and explain the error in or objection to the annual Evaluation Report;

2. Make a good faith effort to quantify the financial impact of the error or objection;

3. State specifically any proposed changes to the annual Evaluation Report that the Party recommends; and

4. Include all documents and workpapers that support the calculation of the error or the facts supporting the objection.

B. SWEPCO shall file a corrected FRR rate or Rebuttal Testimony with or without Exhibits to the errors and objections raised by the Parties.

6. Extension of Term

A. If SWEPCO requests an extension of the initial term of the FRR, SWEPCO shall include such request as part of its fourth annual Evaluation Report filing.

B. SWEPCO shall provide a class cost of service study for historical year-end 2023.

C. The Commission shall enter a decision on SWEPCO's request no later than 30 days after SWEPCO's request for an extension of the term.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-51.1	Sheet 1 of 1
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 51		
Title: DISTRIBUTION RELIABILITY RIDER (DRR)		PSC File Mark Only

AVAILABILITY

The Distribution Reliability Rider is designed to recover Arkansas costs associated with vegetation management and tree trimming incremental to Arkansas jurisdictional costs recovered in base rates for vegetation management. The Arkansas jurisdictional portion of distribution reliability costs are those that are directly assigned to the Arkansas jurisdiction. The class allocators will be determined using the most recently approved FERC account 593 allocation factors for SWEPCO Arkansas. The Distribution Reliability Rider is applicable to and becomes part of each SWEPCO Arkansas jurisdictional rate schedule. This Rider is applicable to energy consumption of retail customers served at secondary and primary service levels and to facilities, premises and loads of such retail customers.

For service billed under applicable rate schedules for which there is not metering, the monthly kilowatt-hour (kWh) usage shall be estimated by the Company and the Distribution Reliability Factor shall be applied to the estimated kWh usage. The Distribution Reliability billing shall be determined by multiplying the total billing kWh for each applicable customer by the Reliability Surcharge Factor for that customer's class for the current month.

ANNUAL DETERMINATION

The initial period for the DRR Factors shall be the forecasted initial 12 months of distribution reliability costs. A True-up Adjustment shall be calculated and reflected in the following year's DRR factor calculation. The True-up Adjustment shall be defined as the difference between the actual DRR costs for the prior year and the revenue received from the DRR Factors. DRR factors shall be filed by the Company with the Commission and shall be accompanied by a set of workpapers sufficient to fully document the calculations of the DRR Factors including any potential True-up Adjustment.

DISTRIBUTION RELIABILITY FACTORS

Major Rate Class	Factors
Residential - Secondary	$0.004713 per kWh
Commercial/Small Industrial – Secondary	$0.003375 per kWh
Commercial/Small Industrial - Primary	$0.001682 per kWh
Municipal – Secondary	$0.003379 per kWh
Lighting – Secondary	$0.004594 per kWh

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ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. TC-1	Sheet 1 of 6	
Replacing:	Sheet No.		
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY			
Kind of Service: Electric			
Title: TABLE OF CONTENTS			PSC File Mark Only

PART I. GENERAL INFORMATION

PART II. EXEMPTION SCHEDULES

PART III. RATE SCHEDULES

ARKANSAS PUBLIC SERVICE COMMISSION

PART III. RATE SCHEDULES (Continued)

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. TC-3 Sheet 3 of 6

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric

Title: TABLE OF CONTENTS

PSC File Mark Only

PART III. RATE SCHEDULES (Continued)

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. TC-4	Sheet 4 of 6	
Replacing:	Sheet No.		
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY			
Kind of Service: Electric			
Title: TABLE OF CONTENTS			PSC File Mark Only

PART III. RATE SCHEDULES (Continued)

THIS SPACE FOR PSC USE ONLY

PART III. RATE SCHEDULES (Continued)

PART IV. POLICY SCHEDULES

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. TC-6	Sheet 6 of 6	
Replacing:	Sheet No.		
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY			
Kind of Service: Electric			
Title: TABLE OF CONTENTS			PSC File Mark Only

PART III. RATE SCHEDULES (Continued)

THIS SPACE FOR PSC USE ONLY

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. E-1.1	Sheet 1 of 2
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Exemption Schedule No. 1		
Title: EXEMPTION FROM COMMISSION RULES		PSC File Mark Only

General Service Rule 4.01 – Deposits from Applicants

SWEPCO was granted exemption to utilize the computerized system of "Pos ID" in evaluating and identifying the credit risk of new applicants for utility service (Docket #98-056-U).

General Service Rule 4.03B – Calculation of Average Bill – For Inadequate Billing History

SWEPCO was granted exemption from General Service Rule 4.03B by clarifying that the basis on which the deposit for a non-residential applicant is calculated will be determined as following:

"When a non-residential applicant requests service in a location where the previous customer at that location was of the same business type and size as the applicant for service, the average bill shall not be more than the average monthly bill for that location for the most recently completed representative 12-month period."

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. E-1.2	Sheet 2 of 2
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Exemption Schedule No. 1		
Title: EXEMPTION FROM COMMISSION RULES		PSC File Mark Only

General Service Rule 5.21 – Transferring Past Due Balances to Other Accounts

SWEPCO was granted exemption from General Service Rule 5.21 by the addition of the following Paragraph.

"C. An account of any Customer, of any class, when the Company receives a written request to have a balance transferred to the requesting Customer's account and when the following information is stated in the letter of request:

(1) Name and account number of the Customer requesting that a balance is to be transferred to their account;
(2) Name and account number of the Customer whose balance is to be transferred; and
(3) A statement that the requesting Customer understands that their own service may be terminated for non-payment if the transferred balance is not paid in full in accordance with any agreed upon payment arrangements."

Rules for Conservation and Energy Efficiency – Section 5.D

SWEPCO was granted a waiver of Section 5.D of the Conservation and Energy Efficiency Rules by Order 22 of Docket 07-082-TF. The waiver allows SWEPCO to implement its Commercial and Industrial Standard Offer Program and associated rebates for new construction.

Rules for Conservation and Energy Efficiency – Section 7.D

SWEPCO was granted a waiver of Section 7.D of the Conservation and Energy Efficiency Rules by Order 22 of Docket 07-082-TF. The waiver allows SWEPCO to implement its Emergency Load Management Standard Offer Program as and Energy Efficiency program.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. GI-1.1 Sheet 1 of 1	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. General Information Schedule No. 1		
Title: UTILITY INFORMATION		PSC File Mark Only

Utility Official: Elizabeth D. Stephens
Regulatory Consultant

Telephone Number: (318) 673-3626

Mailing Address: Southwestern Electric Power Company
P. O. Box 21106
428 Travis Street (71101)
Shreveport, LA 71156

E-Mail: edstephens@aep.com

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. GI-2.1	Sheet 1 of 1	
Replacing:	Sheet No.		
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY			
Kind of Service: Electric	Class of Service: All		
Part III. General Information Schedule No. 2			
Title: Reserved for Future Use			PSC File Mark Only

This Schedule has been removed from the tariff book

Reserved for Future Use

APSC FILED Time: 2/28/2019 2:15:14 PM: Recvd 2/28/2019 2:14:10 PM: Docket 19-008-U-Doc. 39

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-1.1	Sheet 1 of 8
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 1		
Title: STANDARD TERMS AND CONDITIONS		PSC File Mark Only

1. APPLICABLE TO ALL CLASSES OF ELECTRIC SERVICE

In order that all Customers may receive uniform, efficient, and adequate service, electric service will be supplied to and accepted by all Customers receiving service from the Company in accordance with these Terms and Conditions.

2. ORDER FOR SERVICE

When applicable, contract and agreement forms are provided by the Company to show the agreement under which the Customer receives and the Company delivers electric service. Appropriate arrangements will be completed with Customer, or his duly-authorized agent, before service is supplied by the Company.

3. OPTIONAL RATES

The Company's published rate schedules state the conditions under which each is available for electric service. When two or more rates are applicable to a certain class of service, the choice of such rates lies with the Customer.

The Company, at any time upon request, will determine for any Customer the rate best adapted to existing or anticipated service requirements as defined by the Customer, but the Company does not assume responsibility for the selection of such rate or for the continuance of the lowest annual cost under the rate selected.

The Company, lacking knowledge of changes that may occur at any time in the Customer's operating conditions, does not assume responsibility that Customer will be served under the most favorable rate; nor will the Company make refunds covering the difference between the charges under the rate in effect and those under any other rate applicable to the same service.

Rates are normally established on a twelve-month basis and a Customer having selected a rate adapted to his service may not change to another rate within a twelve-month period unless there is a substantial change in the character or conditions of his service. A new Customer will be given reasonable opportunity to determine his service requirements before definitely selecting the most favorable rate therefor.

4. MONTHLY BILLS

Bills for service will be rendered monthly, unless otherwise specified. The term "month" for billing purposes will mean the period between any two consecutive readings of the meters by the Company, such readings to be taken as nearly as practicable every thirty days, but no less than 25 days and no more than 35 days.

Failure to receive a bill in no way exempts Customers from payment for electric service.

The Company makes a special effort to read all meters every month. Sometimes due to adverse weather conditions, dog hazards, damaged equipment, etc., it is not possible to obtain a meter reading and the bill may be estimated. Estimated bills are identified on the bill with an applicable code.

5. DISCONTINUANCE OF SERVICE

When bills for electric service are in arrears, or in case the Customer fails to comply with these Terms and Conditions, the Company will have the right to discontinue electric service to the Customer and to remove its property from the Customer's premises upon mailing notice to address to which the monthly bills are sent. There will be a charge for reconnecting the service to Customers whose service has been disconnected for non-payment of bills.

6. EXCLUSIVE SERVICE ON INSTALLATION CONNECTED TO COMPANY'S SYSTEM

Except as may be specifically permitted under tariffs governing the interconnection or provision of service to small power producers or cogenerators, standard electric rate schedules are based on exclusive use of Company's service.

Except in cases where the Customer has a contract with the Company for breakdown or standby service, no other electric light or power service will be used by the Customer on the same installation in conjunction with the Company's service, either by means of a throw-over switch or any other connection.

The Company will not be required to supply or continue to supply service to any Customer where a portion of Customer's service requirement is obtained from other sources, except when such service is covered by a contract.

The Customer will not sell the electricity purchased from the Company to any other customer, company, or person, and Customer will not deliver electricity purchased from the Company to any connection wherein said electricity is to be used off of the Customer's premises on which the meter is located.

7. CUSTOMER'S INSTALLATION

All wiring and other electrical equipment furnished by the Customer will be installed, operated, and maintained by the Customer at all times in conformity with good electrical practice and with the requirements of the constituted authorities and these Terms and Conditions. Where no public authorities have jurisdiction, Company, for Customer's protection, may require Customer to furnish Company a certificate from wiring electrician that Customer's installation conforms to the National Electrical Code and/or the National Electrical Safety Code. The Company does not assume responsibility for the design, operation, or condition of the Customer's installation.

Service will be delivered to Customer for each premise at one point of delivery to be designated by Company and to conform to Company's service standards. For mutual protection of Customer and Company, only authorized employees of Company are permitted to make and energize the connection between Company's service wire and Customer's service entrance conductors.

8. OWNER'S CONSENT TO OCCUPY

The Company shall have the right to install and maintain equipment in, over and under the Customer's property and shall have access to the Customer's premises for any other purpose necessary for supplying electric service to the Customer. In case the Customer is not the owner of the premises or of the intervening property between the premises and the Company's lines, the Customer will obtain from the property owner or owners the easements or right-of-way necessary to install and maintain in, over or under said premises all such

wires and electrical equipment as are necessary or convenient for supplying electric service to the Customer.

9. MOTOR INSTALLATIONS

For mutual protection of service to all customers, all motor installations will be as follows:

(a) All motors rated in horsepower up to and including 7-1/2 HP and individual air conditioning units with ratings of 65,000 BTUH (ARI rating) or less will be single phase, unless otherwise agreed to by the Company or served in conjunction with other larger three phase loads.

(b) All three phase motors will be equipped with approved starting equipment having low voltage release attachment and properly sized over-current protection in each of the three phases.

10. POWER FACTOR

The Company will not be required to furnish electric service to any Customer with low power factor equipment.

Where Customer has power or heating equipment installed that operates at low power factor, Customer, when requested to do so by the Company, will furnish, at his own expense, suitable corrective equipment to maintain a power factor of 90% lagging, or higher.

Customer will install and maintain in conjunction with any fluorescent lighting, neon lighting, or other lighting equipment having similar load characteristics, auxiliary or other

corrective apparatus that will correct the power factor of such lighting equipment to not less than 90% lagging.

11. PROTECTION OF SERVICE

The Company will not be obligated to serve any devices that have a detrimental effect upon the service rendered to other Customers or upon Company equipment. Where the Customer's use of such a device causes voltage fluctuation of the 60 Hertz wave, clipping of the current, or voltage wave - thereby producing harmonics or a cyclic pulsation between one and sixty Hertz (1 and 60 Hertz), Customer will furnish at his own expense necessary equipment to limit such voltage fluctuation, harmonics, or pulsations so that they will not interfere with other Customers or Company equipment. Where the interference cannot be corrected, the use of such devices must be discontinued.

12. CONTINUOUS SERVICE

The Company will endeavor to maintain continuous service but will not be liable for loss or damage caused by interruption or failure of service or delay in commencing service due to accident to or breakdown of plant, lines, or equipment, strike, riot, act of God, or causes reasonably beyond the Company’s control or due to shutdown for reasonable periods to make repairs to lines or equipment.

In like manner, should the Customer's premises be rendered wholly unfit for the continued operation of the Customer's plant or business, due to any of the causes mentioned above, the Customer's contract, if any, will thereupon be suspended until such time as the plant or premises will have been reconstructed, reconditioned, and reoccupied by the Customer for the purpose of his business.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-1.7	Sheet 7 of 8
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 1		
Title: STANDARD TERMS AND CONDITIONS		PSC File Mark Only

13. INTERRUPTION OF SERVICE

The Company shall not be responsible in damages for any failure to supply electricity, or for interruption, or reversal of the supply, if such failure, interruption, or reversal is without willful default or negligence on its part, nor for interruptions, by under frequency relays or otherwise, to preserve the integrity of the Company's system or interconnected systems.

14. METERING

The electricity used will be measured by a meter or meters to be furnished and installed by the Company at its expense and bills will be calculated upon the registration of such meters. Meters include all measuring instruments. Meter installations will be made in accordance with the Company’s service standards. Customer will provide a sufficient and proper space in a clean and safe place, accessible at all times and free from vibration, for the installation of Company's meters. Company will furnish all meter bases and/or metering enclosures to be installed by Customer on supply side of service equipment to be metered.

15. PROTECTION OF COMPANY'S PROPERTY AND ACCESS TO PREMISES

The Customer will protect the Company's property on the Customer's premises from loss or damage and will permit no one who is not an agent of the Company to remove or tamper with the Company's property.

The Company will have the right of access to the Customer's premises at all reasonable times for the purpose of installing, reading, inspecting, or repairing any meters or devices owned by Company or for the purpose of removing its property.

16. AGENTS CANNOT MODIFY AGREEMENT

No agent has power to amend, modify, or waive any of these Terms and Conditions, or to bind the Company by making any promises or representations not contained herein.

17. SUPERSEDE PREVIOUS TERMS AND CONDITIONS

These Terms and Conditions supersede all Terms and Conditions under which the Company has previously supplied electric service.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-2.1	Sheet 1 of 2
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Residential	
Part III. Rate Schedule No. 2		
Title: RESIDENTIAL SERVICE		PSC File Mark Only

AVAILABILITY

This schedule is available to residential customers for all domestic uses in residences, individual family apartments, and private rooming houses.

Where a portion of a residential unit is used for non-residential purposes, the appropriate non-residential service schedule is applicable to all uses of electric service. However, this rate schedule may be applied to the residential portion of such use provided the Customer's wiring is so arranged that the use of electric service for residential purposes can be metered separately from the non-residential use.

NET MONTHLY RATE

Customer Charge:	$10.00 Per Meter, plus
Kilowatt-hour Charge:	May through September Billing Cycles $0.0702 each for the first 1,500 kilowatt-hours $0.0919 each for all additional kilowatt-hours October through April Billing Cycles $0.0610 per kilowatt-hour

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

Multiple Dwelling: Where service is rendered through one meter to a multiple dwelling unit or apartment house, the amount of the Customer Charge will be multiplied by the number of single residence units served.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-3.1	Sheet 1 of 2
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Residential	
Part III. Rate Schedule No. 3		
Title: ELECTRIC HEATING APPLIANCE RESIDENTIAL SERVICE Closed to New Applications		PSC File Mark Only

AVAILABILITY

This schedule is available to residential customers for all domestic uses in residences, individual family apartments, and private rooming houses under one or both of the following conditions:

1. When a Customer regularly uses one or more Company-approved electric water heaters for all water heating requirements, notifies the Company, and has the installation verified by Company personnel, and/or,
2. When there is a permanently installed electric reverse cycle central system heat pump or a total of five kilowatts or more of permanently installed electric space heating devices which are in regular use for space heating purposes, and the Customer notifies the Company, and has the installation verified by Company personnel.

Where a portion of a residential unit is used for non-residential purposes, the appropriate non-residential service schedule is applicable to all uses of electric service. However, this rate schedule may be applied to the residential portion of such use provided the Customer's wiring is so arranged that the use of electric service for residential purposes can be metered separately from the non-residential use.

NET MONTHLY RATE

Customer Charge:	$10.00 Per Meter, plus
Kilowatt-hour Charge:	May through September Billing Cycles $0.0702 each for the first 1,500 kilowatt-hours $0.0919 each for all additional kilowatt-hours October through April Billing Cycles $0.0610 each for the first 500 kilowatt-hours $0.0380 each for all additional kilowatt-hours

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ARKANSAS PUBLIC SERVICE COMMISSION

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: Residential

Part III. Rate Schedule No. 3

Title: ELECTRIC HEATING APPLIANCE RESIDENTIAL SERVICE
Closed to New Applications

PSC File Mark Only

ADJUSTMENTS:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

Multiple Dwelling: Where service is rendered through one meter to a multiple dwelling unit or apartment house, the amount of the Customer Charge will be multiplied by the number of single residence units served.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original **Sheet No:** R-4.1 Sheet 1 of 1

Replacing: **Sheet No:**

Name of Company: SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric **Class of Service:**

Part III.
Title: RESERVED FOR FUTURE USE

PSC File Mark Only

Reserved for future use

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-5.1	Sheet 1 of 2
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 5		
Title: GENERAL SERVICE		PSC File Mark Only

AVAILABILITY

This rate schedule is available to all customers except multiple or individual dwellings or apartment houses, on an annual basis for secondary service for lighting, heating and power, or combination of lighting, heating and power where facilities of adequate capacity and suitable phase and voltage are available. Service will be supplied at one point of delivery through one meter. This schedule is available for Demand up to 50 kilowatts.

NET MONTHLY RATE

Customer Charge:	\$10.60 Per Meter, plus \$6.51 for each Kilowatt of Billing Demand in excess of 6 Kilowatts of Billing Demand
Kilowatt-hour Charge:	May through September Billing Cycles \$0.0456 per kilowatt-hour October through April Billing Cycles \$0.0373 per kilowatt-hour

Determination of Kilowatts of Billing Demand: The Kilowatts of Billing Demand for each month will be the average kilowatt load used by the Customer during the 15-minute period of maximum use during the month. The Kilowatts of Billing Demand will be subject to the Power Factor Adjustment Clause.

Contract Minimum: When a contract minimum is applicable, the Customer's minimum monthly bill will not be less than the applicable charge for the contracted demand minimum plus the applicable Fuel and Tax Adjustments.

<u>Capacity Charge for Highly Fluctuating Loads</u>: Should the Customer operate equipment with highly fluctuating, intermittent, or abnormal characteristics that make it necessary for the Company to install special facilities to serve the Customer or to prevent disturbances to the service to other Customers, an additional Distribution Function charge of $1.58 per month per kilovolt-ampere (kVA) or fraction thereof of transformer capacity installed by the Company to serve the Customer will be added to the Customer's bill.

<u>Power Factor Adjustment</u>: The Company reserves the right to determine the power factor of the Customer's installation served hereunder. Should the average lagging power factor during the month be determined to be below 90%, the Customer's Kilowatts of Billing Demand will be adjusted by multiplying the Kilowatts of Billing Demand by 90% and dividing by the average lagging power factor.

<u>Adjustments</u>:

<u>Fuel Adjustment</u>: In addition to all other charges, the amount of the Customer’s bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

<u>Tax Adjustment</u>: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

<u>PAYMENT FOR SERVICE</u>

Payment for Service Rider - See Rate Schedule 44.

<u>TERMS AND CONDITIONS</u>

Service will be furnished under Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-6.1 Sheet 1 of 3	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 6		
Title: LIGHTING AND POWER		PSC File Mark Only

AVAILABILITY

This rate schedule is available to all customers, except multiple or individual dwellings or apartment houses, on an annual basis for service for lighting, heating and power or combination of lighting, heating and power where facilities of adequate capacity and suitable phase and voltage are available. Service will be supplied at one point of delivery through one meter. This schedule is available for Billing Demands from 50 kilowatts to 10,000 kilowatts.

NET MONTHLY RATE

Secondary Service:

May through September Billing Cycles
$12.73 for each Kilowatt of Billing Demand in the month, but not less than $636.50

$0.0270 per kilowatt-hour

October through April Billing Cycles
$10.22 for each Kilowatt of Billing Demand in the month, but not less than $511.00

$0.0079 per kilowatt-hour

Primary Service:

May through September Billing Cycles
$11.16 for each Kilowatt of Billing Demand in the month, but not less than $558.00

$0.02573 per kilowatt-hour

October through April Billing Cycles
$8.80 for each Kilowatt of Billing Demand in the month, but not less than $440.00

$0.0074 per kilowatt-hour

Determination of Kilowatts of Billing Demand: The Kilowatts of Billing Demand for each month will be the average kilowatt load used by the Customer during the 15-minute period of maximum use during the month, but not less than 70% of the highest Kilowatts of Billing Demand established during the 11 preceding months. The Kilowatts of Billing Demand will be subject to the Power Factor Adjustment Clause.

Contract Minimum: When a contract minimum is applicable, the Customer's minimum monthly bill will not be less than the applicable charge for the contracted demand minimum plus the applicable Fuel and Tax Adjustments.

Capacity Charge for Highly Fluctuating Loads: Should the Customer operate equipment with highly fluctuating, intermittent, or abnormal characteristics that make it necessary for the Company to install special facilities to serve the Customer or to prevent disturbances to the service to other Customers, an additional Distribution Function charge of $1.58 per month per kilovolt-ampere (kVA) or fraction thereof of transformer capacity installed by the Company to serve the Customer will be added to the Customer's bill.

Power Factor Adjustment: The Company reserves the right to determine the power factor of the Customer's installation served hereunder. Should the average lagging power factor during the month be determined to be below 90%, the Customer's Kilowatts of Billing Demand will be adjusted by multiplying the Kilowatts of Billing Demand by 90% and dividing by the average lagging power factor.

Primary Service: Applicable when electric service is provided at the Company's primary distribution voltage of 12.5 kV or higher and the Customer furnishes and maintains all necessary transformation equipment beyond this point.

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under Company's Standard Terms and Conditions

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ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-7.1	Sheet 1 of 2	
Replacing:	Sheet No.		
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY			
Kind of Service: Electric	Class of Service: As Applicable		
Part III. Rate Schedule No. 7			
Title: LARGE LIGHTING AND POWER			PSC File Mark Only

AVAILABILITY

This rate schedule is available to all customers on an annual basis for service for lighting, heating and power or combination of lighting, heating and power where facilities of adequate capacity and suitable phase and voltage are available. Service will be supplied at one point of delivery though one meter. This schedule is available for Billing Demands of 10,000 kilowatts or greater.

NET MONTHLY RATE

Transmission Service:

May through September Billing Cycles
$88,100 for the first 10,000 Kilowatts of Billing Demand or less in the month

$8.81 each for all kilowatts in excess of 10,000 Kilowatts of Billing Demand in the month

$0.0223 per kilowatt-hour

October through April Billing Cycles
$66,500 for the first 10,000 Kilowatts of Billing Demand or less in the month

$6.65 each for all kilowatts in excess of 10,000 Kilowatts of Billing Demand in the month

$0.0060 per kilowatt-hour

Determination of Kilowatts of Billing Demand: The Kilowatts of Billing Demand for each month will be the average kilowatt load used by the Customer during the 15-minute period of maximum use during the month but not less than 80% of the highest Kilowatts of Billing Demand established during the 11 preceding months. The Kilowatts of Billing Demand will be subject to the Power Factor Adjustment Clause.

Contract Minimum: When a contract minimum is applicable, the Customer's minimum monthly bill will not be less than the applicable charge for the contracted demand minimum plus the applicable Fuel and Tax Adjustments.

Capacity Charge for Highly Fluctuating Loads: Should the Customer operate equipment with highly fluctuating, intermittent, or abnormal characteristics that make it necessary for the Company to install special facilities to serve the Customer or to prevent disturbances to the service to other Customers, an additional Distribution Function charge of $1.58 per month per kilovolt-ampere (kVA) or fraction thereof of transformer capacity installed by the Company to serve the Customer will be added to the Customer's bill.

Power Factor Adjustment: The Company reserves the right to determine the power factor of the Customer's installation served hereunder. Should the power factor at the time of establishment of any 15-minute period of maximum use during the month be determined to be below 90%, the Customer's Kilowatts of Billing Demand will be adjusted by multiplying the Kilowatts of Billing Demand by 90% and dividing the result by the actual power factor at the time of maximum use.

Transmission Service: Applicable when electric service is provided at the Company's available transmission voltages of 69 kV or higher and the Customer furnishes and maintains all necessary transformation equipment beyond this point.

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer’s bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-8.1 Sheet 1 of 4	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Industrial - Time of Use	
Part III. Rate Schedule No. 8		
Title: LIGHTING AND POWER – TIME OF USE		PSC File Mark Only

AVAILABILITY

This rate schedule is available to Industrial customers on an annual basis having loads of 500 Kilowatts of maximum demand or greater. Service will be provided at one point of delivery through one meter where facilities of adequate capacity and suitable phase and voltage are available.

NET MONTHLY RATE

Secondary Service: **On-Peak** $21.33 for each Kilowatt of On-Peak Billing Demand in the month but not less than $1,066.50

$0.1039 per kilowatt-hour

Off-Peak $8.82 for each Kilowatt of Off-Peak Billing Demand in the month, but not less than $441.00

$0.0161 per kilowatt-hour

Primary Service: **On-Peak** $16.52 for each Kilowatt of On-Peak Billing Demand in the month, but not less than $826.00

$0.1005 per kilowatt-hour

Off-Peak $6.43 for each Kilowatt of Off-Peak Billing Demand in the month, but not less than $321.50

$0.0142 per kilowatt-hour

Determination of Kilowatts of Billing Demand: Billing Demands will be separately maintained and applied for the On-Peak and Off-Peak periods. Billing Demands shall be calculated as follows:

On-Peak: The Kilowatts of On-Peak Billing Demand for each month in which On-Peak period rates are applicable shall be the average kilowatt load used by the customer during the 15-minute period of maximum use during that month's On-Peak period, but not less than 70% of the highest Kilowatts of Billing Demand established during the On-Peak period during the 11 preceding months. The Kilowatts of On-Peak Billing Demand shall be subject to the Power Factor Adjustment Clause.

Off-Peak: The Kilowatts of Off-Peak Billing Demand for each month shall be the average kilowatt load used by the Customer during the 15-minute period of maximum use during the Off-Peak period of that month, but not less than 70% of the highest Kilowatts of Billing Demand established during either the On-Peak or Off-Peak period during the 11 preceding months. The Kilowatts of Off-Peak Billing Demand shall be subject to the Power Factor Adjustment Clause.

Contract Minimum: The customer's minimum bill shall not be less than the applicable charge for the contracted demand minimum plus the applicable Fuel and Tax Adjustments and in no event shall the contract demand minimum be less than 500 kilowatts.

Definition of Rating Periods:

On-Peak: The On-Peak hours shall be the hours from 1:01 p.m. through 7:00 p.m. during weekdays, excluding national holidays, during the months of July, August and September.

Off-Peak: The Off-Peak hours shall be all hours other than the On-Peak hours.

Capacity Charge for Highly Fluctuating Loads: Should the Customer operate equipment with highly fluctuating, intermittent, or abnormal characteristics that make it necessary for the Company to install special facilities to serve the Customer or to prevent disturbances to the service to other Customers, an additional Distribution Function charge of $1.58 per month per kilovolt-ampere (kVA) or fraction thereof of transformer capacity installed by the Company to serve the Customer will be added to the Customer's bill.

Power Factor Adjustment: The Company reserves the right to determine the power factor of the Customer's installation served hereunder. Should the average lagging power factor during the month be determined to be below 90%, the Customer's Kilowatts of Billing Demand in each rating period will be adjusted by multiplying the Kilowatts of Billing Demand in each rating period by 90% and dividing by the average lagging power factor.

Primary Service: Applicable when electric service is provided at the Company's primary distribution voltage of 12.5 kV or higher and the Customer furnishes and maintains all necessary transformation equipment beyond this point.

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per Kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-9.1	Sheet 1 of 6
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Pulp & Paper Mill	
Part III. Rate Schedule No. 9		
Title: PULP AND PAPER MILL SERVICE		PSC File Mark Only

AVAILABILITY

This rate schedule is available to pulp and paper mills on an annual basis where facilities of adequate capacity and suitable phase and voltage are available. Service will be supplied at one point of delivery through one meter.

PULP AND PAPER MILL RATE

The Company shall render a bill and the Customer shall pay for electric service supplied each month an amount to be determined in the following manner:

$154,200	Each month during the life of the contract for which the Customer will be allowed the use of up to 20,000 Kilowatts of Billing Demand determined as hereinafter provided, plus
$7.71	Per Kilowatt of Billing Demand each month for the maximum number of Kilowatts of Billing Demand in any one month of the 12-month period ending with the current month that are in excess of 20,000 Kilowatts of Billing Demand, plus
$0.0103	Per kilowatt-hour for all kilowatt-hours supplied during the month

Determination of Kilowatts of Billing Demand: The Kilowatts of Billing Demand will be measured and will be the kilowatt load supplied during the 15-minute period of maximum use in the 12-month period ending with the current month, but never less than 20,000 kilowatts.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-9.2 Sheet 2 of 6	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Pulp & Paper Mill	
Part III. Rate Schedule No. 9		
Title: PULP AND PAPER MILL SERVICE		PSC File Mark Only

Power Factor Adjustment: In the event the power factor at the time of establishment of any 15-minute period of maximum use during the month is less than 90%, the Kilowatts of Billing Demand shall be adjusted by multiplying the Kilowatts of Billing Demand by 90% and dividing the result by the actual power factor at the time of said maximum use, and the result so obtained shall be Kilowatts of Billing Demand for the month, but never less than the maximum number of Kilowatts of Billing Demand in the 12-month period ending with the current month and, in any event, not less than 20,000 kilowatts.

Minimum Monthly Bill: The minimum monthly bill will be the maximum Kilowatts of Billing Demand charge during the 12-month period ending with the current month, but never less than the charge of $154,200.00 for the first 20,000 Kilowatts of Billing Demand or less, and plus or minus the Fuel Adjustment charge plus the Tax Adjustment charge.

Annual Guarantee: It is mutually understood and agreed that in order for Company to be equitably compensated for permitting Customer to operate its plant generators in parallel with Company system the Customer will take or pay for, each year ending on October 31, a minimum of 2,000 hours times the maximum number of Kilowatts of Billing Demand previously determined, but not less than 40,000,000 kilowatt-hours per year.

Kilowatt-hours used during periods of turbine-generator overhaul, maintenance or emergency shall not be included in the Annual Guarantee.

Conjunctive Rate Provisions: When the Pulp and Paper Mill rate is used in conjunction with the Supplementary, Backup, Maintenance, and As-Available Standby Power Service rate, the Power Factor Adjustment and the following provisions for turbine-generator overhaul, emergency power, and maintenance power will not apply.

<u>Turbine-Generator Overhaul</u>: It is recognized that it will be necessary for the integrated operations of the turbine-generators of Customer and power service of the Company, that scheduled overhaul periods on the equipment of the Customer must be fitted into the similar schedules of the Company. During periods of agreed overhaul the Kilowatts of Billing Demand shall be based on actual kilowatts during such overhaul period but in no event less than maximum Kilowatts of Billing Demand previously established under normal operations. The Kilowatts of Billing Demand established during overhaul period will not be used to determine the maximum kilowatt load previously established.

<u>Emergency Power</u>: The Company recognizes that actual emergencies can occur to Customer's generating facilities and that Customer may desire assistance in supplying such loss of generating capability not to exceed 30 days for any one emergency.

The Company will, to the extent of facilities then available, make every reasonable effort to supply Customer's emergency. Customer agrees to correct its emergency conditions as soon as reasonably possible. An authorized representative of the Customer shall notify Company's system operations center's authorized representative at time of the beginning of the emergency, the cause and the expected duration thereof. The Customer's representative will also notify Company at the time the emergency ends. Such notices shall be confirmed by letter containing the same information to the authorized representative within 24 hours of the start and end of the emergency.

The Customer shall pay the Company for all emergency load and energy supplied on the following basis:

$9.30	per Kilowatt of Billing Demand in excess of the Determination of Kilowatts of Billing Demand under normal firm load conditions or a minimum of 20,000 kilowatts, plus
$0.0223	per kilowatt-hour plus Fuel Adjustment charge or 110% of Company's highest kilowatt-hour cost either purchased or generated during the time of the emergency, whichever is greater. The kilowatt-hours will be the sum of the kilowatt-hours determined by multiplying the Maximum demand in each hour of the emergency that is in excess of the determination of Kilowatts of Billing Demand under normal firm load conditions times one hour.

Maintenance Power: To enable the Customer to repair and maintain the operating efficiency of its facilities, the Customer may purchase additional power referred to as "Maintenance Power" from the Company. Maintenance Power shall be arranged in advance by telephone

requests to the Company's system operation center. Such Maintenance Power will be supplied, provided the Company is reasonably certain that a system peak will not be created during this period and providing the Company in its judgment has adequate capacity in its own system to supply the requested demand. Maintenance Power requests will be for a limited period of time as specified by Company. Maintenance Power will be extremely limited or unavailable during the months of June, July, August and September. Company reserves the right to terminate Customer's purchase of Maintenance Power due to changes within this system with one-hour notice to Customer. Maintenance Power will be provided only during periods when the Customer is receiving firm power from the Company. The Customer will pay for such maintenance power on whichever of the following basis is applicable:

Maintenance Power - Used only from 11:00 p.m. on Fridays until 7:00 a.m. on Mondays and from 12:01 a.m. on holidays to 7:00 a.m. the following morning.

$3.85	per Kilowatt of Billing Demand in excess of the Determination of Kilowatts of Billing Demand under normal firm load conditions or a minimum of 20,000 kilowatts, plus
	the normal charges per kilowatt-hour as provided in the rate schedule.

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Maintenance Power - Used at any time in addition to or including 11:00 p.m. on Fridays until 7:00 a.m. on Mondays and from 12:01 a.m. on holidays to 7:00 a.m. the following morning.

$7.68 per Kilowatt of Billing Demand in excess of the Determination of Kilowatts of Billing Demand under normal firm load conditions or a minimum of 20,000 kilowatts, plus

the normal charges per kilowatt-hour as provided in the rate schedule.

The Kilowatts of Billing Demand created during an agreed to use of Maintenance Power in excess of the Determination of Kilowatts of Billing Demand under normal firm load conditions will not be used to determine the maximum kilowatt load previously established.

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

AVAILABILITY

This schedule is available on an annual basis for lighting and power to municipal installations in communities where the Company has a franchise for the generation, distribution, and sale of electricity, together with a standard contract for the operation of a street lighting system when the Customer purchases its entire lighting and power requirements from the Company.

NET MONTHLY RATE

Customer Charge:	$7.36 per meter, plus
Kilowatt-hour Charge:	May through September Billing Cycles $0.0557 per kilowatt-hour October through April Billing Cycles $0.0494 per kilowatt-hour

Minimum Monthly Bill: The Minimum Monthly Bill will be $1.76 per Kilowatt of Maximum Demand established during the 11 preceding months, but not less than $7.36. For Minimum Monthly Bills rated in horsepower, each horsepower will be considered equal to 3/4 kilowatt.

Determination of Kilowatts of Maximum Demand: The Kilowatts of Maximum Demand for each month will be the average kilowatt load used by the Customer during the 15-minute period of maximum use during the month. The Kilowatts of Maximum Demand will be subject to the Power Factor Adjustment Clause.

Contract Minimum: When a contract minimum is applicable, the Customer's minimum monthly bill will not be less than the applicable charge for the contracted demand minimum plus the applicable Fuel and Tax Adjustments.

ARKANSAS PUBLIC SERVICE COMMISSION

Capacity Charge for Highly Fluctuating Loads: Should the Customer operate equipment with highly fluctuating, intermittent, or abnormal characteristics that make it necessary for the Company to install special facilities to serve the Customer or to prevent disturbances to the service to other Customers, an additional Distribution Function charge of $1.58 per month per kilovolt-ampere (kVA) or fraction thereof of transformer capacity installed by the Company to serve the Customer will be added to the Customer's bill.

Power Factor Adjustment: The Company reserves the right to determine the power factor of the Customer's installation served hereunder. Should the average lagging power factor during the month be determined to be below 90%, the Customer's Kilowatts of Maximum Demand will be adjusted by multiplying the Kilowatts of Maximum Demand by 90% and dividing by the average lagging power factor.

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer’s bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under Company's Standard Terms and Conditions

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-11.1 Sheet 1 of 3	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Municipal	
Part III. Rate Schedule No. 11		
Title: MUNICIPAL PUMPING		PSC File Mark Only

AVAILABILITY

This schedule is available on an annual basis for all municipal water and sewerage pumping, with the exception of standby, breakdown, or auxiliary service, in communities in which the Company has a franchise for the generation, distribution, and sale of electricity, together with a standard contract for the generation, distribution, and sale of electricity, together with a standard contract for the operation of a street lighting system, when the Customer purchases its entire lighting and power requirements from the Company.

CHARACTER OF SERVICE

Power and energy supplied under this schedule will be at either primary or secondary voltage, depending on the Customer's requirements and the availability of such voltage from the Company's established primary or secondary circuits.

MEASUREMENT OF POWER AND ENERGY

Power and energy supplied hereunder will be measured by metering installations at each point of delivery and the kilowatt-hours registered at all points of delivery will be combined to determine the total kilowatt-hours to be used in computing the Customer's monthly bill under this schedule.

NET MONTHLY RATE

Customer Charge:	$7.36 per meter, plus
Kilowatt-hour Charge:	May through September Billing Cycles $0.0492 per kilowatt-hour
	October through April Billing Cycles $0.0426 per kilowatt-hour

Minimum Monthly Bill: The Minimum Monthly Bill will be $1.76 per Kilowatt of Maximum Demand established during the 11 preceding months, but not less than $7.36. For Minimum Monthly Bills rated in horsepower, each horsepower will be considered equal to 3/4 kilowatt.

Determination of Kilowatts of Maximum Demand: The Kilowatts of Maximum Demand for each month will be the average kilowatt load used by the Customer during the 15-minute period of maximum use during the month. The Kilowatts of Maximum Demand will be subject to the Power Factor Adjustment Clause.

Contract Minimum: When a contract minimum is applicable, the Customer's minimum monthly bill will not be less than the applicable charge for the contracted demand minimum plus the applicable Fuel and Tax Adjustments.

Capacity Charge for Highly Fluctuating Loads: Should the Customer operate equipment with highly fluctuating, intermittent, or abnormal characteristics that make it necessary for the Company to install special facilities to serve the Customer or to prevent disturbances to the service to other Customers, an additional Distribution Function charge of $1.58 per month per kilovolt-ampere (kVA) or fraction thereof of transformer capacity installed by the Company to serve the Customer will be added to the Customer's bill.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-11.3 Sheet 3 of 3	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Municipal	
Part III. Rate Schedule No. 11		
Title: MUNICIPAL PUMPING		PSC File Mark Only

Power Factor Adjustment: The Company reserves the right to determine the power factor of the Customer's installation served hereunder. Should the average lagging power factor during the month be determined to be below 90%, the Customer's Kilowatts of Maximum Demand will be adjusted by multiplying the Kilowatts of Maximum Demand by 90% and dividing by the average lagging power factor.

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer’s bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. R-12.1 Sheet 1 of 2

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: Municipal

Part III. Rate Schedule No. 12

Title: MUNICIPAL STREET LIGHTING
(no new installations allowed)

PSC File Mark Only

AVAILABILITY

This schedule is available for municipal street lighting purposes in any community in which the Company has a franchise for the generation, distribution and sale of electricity, and where the Company furnishes, installs, owns, operates and maintains the facilities. No new installations will be allowed on this schedule. As existing mercury vapor fixtures and/or ballasts need to be replaced on or after April 1, 2007, the Customer will have the option to transfer to another open tariff offering.

TYPE OF SERVICE

The lights shall burn every night from dusk to dawn.

NET MONTHLY RATE

Rate Modifier	Description	Rate Per Lamp	Company Will Invest Up to But Not to Exceed – Per Lamp
	Mercury Vapor		
031	75 Watt	$3.76	$100
032	100 Watt	$3.82	$105
033	175 Watt	$3.92	$110
028	400 Watt	$4.26	$165 (1)
035	400 Watt	$4.67	$165 (1)
036*	400 Watt	$4.67	$165 (1)
037	400 Watt	$6.98	$250 (2)
039	400 Watt	$7.37	$285 (1)
041	400 Watt	$12.47	$450 (2)

*Series
(1) On wood pole
(2) On steel pole

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: Municipal

Part III. Rate Schedule No. 13

Title: MUNICIPAL STREET LIGHTING & PARKWAY LIGHTNG (no new installations allowed)

PSC File Mark Only

AVAILABILITY

This schedule is available for municipal street and parkway lighting systems installed in any community in which the Company has a franchise for the generation, distribution and sale of electricity. This schedule is applicable to existing facilities only with no new installations allowed. As existing mercury vapor fixtures and/or ballasts need to be replaced on or after April 1, 2007, the Customer will have the option to transfer to another open tariff offering. As existing metal halide or high pressure sodium facilities need to be replaced and existing inventory is depleted, the Customer will have the option to transfer to another open tariff offering.

TYPE OF SERVICE

The Company will furnish, install, own, operate, maintain, clean and repair the street and parkway lighting system of design as mutually approved by the Customer and the Company. The lamps will be controlled to burn from dusk to dawn. The Customer agrees to provide, at no cost to the Company, all required right-of-way together with tree trimming permits for installation of the system and any permit necessary to allow Company the right to use highway, parkway and street right-of-way for maintenance of the system.

NET MONTHLY RATE

Rate Modifier	Description	kWh	Monthly Rate Per Lamp
	Mercury Vapor		
284	100 Watt	42	$2.75
285	175 Watt	68	$2.78
287	400 Watt	155	$3.57
288	1000 Watt	364	$5.34

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-13.2	Sheet 2 of 3
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Municipal	
Part III. Rate Schedule No. 13		
Title: MUNICIPAL STREET LIGHTING & PARKWAY LIGHTNG (no new installations allowed)		PSC File Mark Only

Rate Modifier	Description	kWh	Monthly Rate Per Lamp
	Metal Halide		
282	400 Watt	156	$4.09
283	1000 Watt	373	$6.26
	High Pressure Sodium		
295	70 Watt	35	$2.92
290	100 Watt	49	$2.94
294	150 Watt	59	$2.94
291	250 Watt	105	$3.39
292	400 Watt	165	$3.76
293	1000 Watt	388	$6.23

Facilities Charge:

There will be a charge each month equal to:

1.46% times the amount of the Company investment in the system to compensate the Company for its investment and maintenance thereon, and/or

0.69% times the amount of the Customer contribution in the system to compensate the Company for maintenance thereon.

Adjustments**:**

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-14.1 Sheet 1 of 2	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 14		
Title: MUNICIPAL STREET LIGHITNG (no new installations allowed)		PSC File Mark Only

Rate for 100 watt mercury vapor luminaries mounted on ornamental standards supplied by underground circuits.

ELECTRIC SERVICE LINE EXTENSION AGREEMENT SIGNED WITH
James R. Hale, Developer, Virginia Hills Addition
and
Oak Manor Developing Company

Rate Modifier	Description	kWh	Total
030*	Mercury Vapor 100 Watt	42	$4.89

This installation was made prior to promulgation of our standard rate for Mercury Vapor Lamps. Under the Street Lighting Schedule this installation is considered as "Ornamental Standards" with a Customer contribution for all investment in excess of $220 per lamp. Billing is to the City of Fayetteville, Arkansas.

* Note: This rate is applicable to the presently installed system only with no new installations allowed. As existing mercury vapor fixtures and/or ballasts need to be replaced on or after April 1, 2007, the Customer will have the option to transfer to another open tariff offering.

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ARKANSAS PUBLIC SERVICE COMMISSION

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-15.1 Sheet 1 of 3	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 15		
Title: MUNICIPAL STREET & PARKWAY LIGHTING		PSC File Mark Only

AVAILABILITY

No new mercury vapor installations will be allowed on this schedule on or after April 1, 2007. As existing mercury vapor fixtures and/or ballasts need to be replaced on or after April 1, 2007, the Customer will have the option to transfer to another open tariff offering.

This schedule is available for municipal street and parkway lighting systems installed in any community in which the Company has a franchise for the generation, distribution, and sale of electricity.

TYPE OF SERVICE

The Company will furnish, install, own, operate, maintain, clean and repair the street and parkway lighting system of design as mutually approved by the Customer and the Company. The lamps will be controlled to burn from dusk to dawn. The Customer agrees to provide, at no cost to the Company, all required right-of-way together with tree trimming permits for installation of the system and any permit necessary to allow Company the right to use highway, parkway and street right-of-way for maintenance of the system.

NET MONTHLY RATE

Rate Modifier	Description	kWh	Monthly Rate Per Lamp
	Mercury Vapor		
508	175 Watt	68	$3.92
509	400 Watt	155	$4.67
	Metal Halide		
510	400 Watt	156	$4.09
511	1000 Watt	373	$6.26

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-15.2 Sheet 2 of 3	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 15		
Title: MUNICIPAL STREET & PARKWAY LIGHTING		PSC File Mark Only

Rate Modifier	Description	kWh	Monthly Rate Per Lamp
	High Pressure Sodium		
512	100 Watt	49	$2.94
513	250 Watt	105	$3.39
514	400 Watt	165	$3.76
515	1000 Watt	388	$6.23
	Light Emitting Diode		
LED 01	0-100 Watts - Less than 10,000 Lumens	20	$3.68
LED 02	101-250 Watts – 10,000-25000 Lumens	56	$5.54
LED 03	Over 250 Watts – over 25,000 Lumens	100	$9.41

Facilities Charge:

There will be a charge each month equal to:

1.46% times the amount of the Company investment in the system to compensate the Company for its investment and maintenance thereon, and/or

0.69% times the amount of the Customer contribution in the system to compensate the Company for maintenance thereon.

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

ARKANSAS PUBLIC SERVICE COMMISSION

REPLACEMENT, REMOVAL, OR DISCONNECT

When a customer requests that the Company replace an existing non-LED lighting system with an LED lighting system the customer may be required to pay to the Company a one-time Conversion Fee of $95.

When a customer requests that the Company disconnect or remove an existing LED lighting system the customer may be required to pay to the Company a one-time Removal Fee of $145.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-16.1	Sheet 1 of 2
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 16		
Title: PUBLIC STREET & HIGHWAY LIGHTING - ENERGY ONLY (closed to new additions)		PSC File Mark Only

AVAILABILITY

This schedule is available for electric energy used in operation of public highway lighting systems at any point on the Company's interconnected system where secondary voltage service is available. This rate is applicable to existing luminaires only with no new additions allowed.

TYPE OF SERVICE

The Company will make available single phase, secondary voltage electric service from dusk to dawn at Customer points of service located adjacent to Company lines of adequate capacity and suitable voltage.

NET MONTHLY RATE

Rate Modifier	Description	kWh	Monthly Rate Per Lamp
	Mercury Vapor		
255	175 Watt	68	$2.84
251	400 Watt	155	$4.05
253	1000 Watt	364	$4.70

ARKANSAS PUBLIC SERVICE COMMISSION

Rate Modifier	Description	kWh	Rate Per Lamp Per Month
	Metal Halide		
256	400 Watt	156	$4.07
257	1,000 Watt	373	$7.09
	High Pressure Sodium		
258	70 Watt	35	$2.38
259	100 Watt	49	$2.57
261	250 Watt	105	$3.36
262	400 Watt	165	$4.19
263	1000 Watt	388	$7.30.

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

AVAILABILITY

This schedule is available for electric service used in the operation of publicly-owned highway lighting systems utilizing luminaries mounted at heights not exceeding forty (40) feet above ground level and where the Company has no investment in facilities beyond the delivery point of service. This rate is applicable to existing luminaires only with no new additions allowed.

TYPE OF SERVICE

The Company will make available single phase, secondary voltage electric service from dusk to dawn at Customer points of service adjacent to Company lines of adequate capacity and suitable voltage.

The Customer will own, install, operate, and maintain its highway lighting system from the point of service connection with the Company lines. The Company will be responsible for relamping and will replace glassware to be furnished by Customer.

The Customer will provide the Company, at no cost to the Company, any permit necessary to allow the Company the right to use highway right-of-way for maintenance of the system.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-17.2 Sheet 2 of 3	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 17		
Title: PUBLIC STREET AND HIGHWAY LIGHTING (closed to new additions)		PSC File Mark Only

NET MONTHLY RATE

Rate Modifier	Description	kWh	Rate Per Lamp Per Month
	Mercury Vapor		
051	175 Watt	68	$3.02
074	400 Watt	155	$4.46
	Metal Halide		
052	400 Watt	156	$4.48
053	1000 Watt	373	$7.25
	High Pressure Sodium		
055	100 Watt	49	$2.71
057	250 Watt	105	$3.64
058	400 Watt	165	$4.39
059	1000 Watt	388	$7.46

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

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Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. R-18.1 Sheet 1 of 2

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: As Applicable

Part III. Rate Schedule No. 18

Title: PUBLIC STREET AND HIGHWAY LIGHTING –ENERGY ONLY

PSC File Mark Only

AVAILABILITY

This schedule is available for electric energy used in operation of public highway lighting systems at any point on the Company's interconnected system where secondary voltage service is available.

TYPE OF SERVICE

The Company will make available single phase, secondary voltage electric service from dusk to dawn at Customer points of service located adjacent to Company lines of adequate capacity and suitable voltage.

NET MONTHLY RATE

Rate Modifier	Description	kWh	Rate Per Lamp Per Month
	Mercury Vapor		
265	175 Watt	68	$2.84
266	400 Watt	155	$4.05
	Metal Halide		
267	400 Watt	156	$4.07
268	1000 Watt	373	$7.09
	High Pressure Sodium		
269	100 Watt	49	$2.57
270	250 Watt	105	$3.36
271	400 Watt	165	$4.19
272	1000 Watt	388	$7.30

ARKANSAS PUBLIC SERVICE COMMISSION

Net Monthly Rate For Units Not Listed Above:
The Net Monthly Rate for lighting units not listed above will be calculated by the Company using the following formula:

Monthly kWh used by the lighting unit X $0.03605 = Net Monthly Rate rounded to the nearest $0.01, but not less than $1.00.

Where: Monthly kWh used by the lighting unit = ((Input watts rounded to the nearest whole number X 4,000 hours) / 1,000) / 12, rounded to the nearest whole number.

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

AVAILABILITY

This schedule is available for electric service used in the operation of publicly-owned highway lighting systems utilizing luminaries mounted at heights not exceeding forty (40) feet above ground level and where the Company has no investment in facilities beyond the delivery point of service.

TYPE OF SERVICE

The Company will make available single phase, secondary voltage electric service from dusk to dawn at Customer points of service adjacent to Company lines of adequate capacity and suitable voltage.

The Customer will own, install, operate, and maintain its highway lighting system from the point of service connection with the Company lines. The Company will be responsible for relamping and will replace glassware to be furnished by Customer.

The Customer will provide the Company, at no cost to the Company, any permit necessary to allow the Company the right to use highway right-of-way for maintenance of the system.

NET MONTHLY RATE

Rate Modifier	Description	kWh	Rate Per Lamp Per Month
	Mercury Vapor		
500	175 Watt	68	$3.02
501	400 Watt	155	$4.46
	Metal Halide		
502	400 Watt	156	$4.48
503	1000 Watt	373	$7.25
	High Pressure Sodium		
504	100 Watt	49	$2.71
505	250 Watt	105	$3.64
506	400 Watt	165	$4.39
507	1000 Watt	388	$7.46

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-20.1 Sheet 1 of 3	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Lighting	
Part III. Rate Schedule No. 20		
Title: PRIVATE LIGHTING (no new installations allowed)		PSC File Mark Only

AVAILABILITY

This schedule is available for existing private lighting systems only with no new installations allowed. As existing mercury vapor fixtures and/or ballasts need to be replaced on or after April 1, 2007, the Customer will have the option to transfer to another open tariff offering.

TYPE OF SERVICE

The Company will furnish, install, own, operate, and maintain complete luminaire units of approved design with an automatic control device for lights to burn from dusk to dawn for an agreed upon term of years to continue thereafter in automatically recurring yearly periods unless and until terminated at the end of any yearly period by 30 days prior notice from either party to the other.

The Customer agrees to provide all required right-of-way together with tree trimming permits and to protect the Company's equipment from damage.

The Company shall have the right to build pole line and install equipment upon the Customer's property and shall have access to the Customer's premises for any other purpose necessary for the performance of this service. The facilities installed by the Company will remain the property of the Company and may be removed by Company upon discontinuance of service.

The Company will exercise reasonable diligence at all times to furnish Customer service as contracted for, but will not be liable in damages for any interruption, deficiency or failure of service. The Company reserves the right to interrupt the service when such interruption is necessary for repairs to its lines or equipment.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-20.2	Sheet 2 of 3
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Lighting	
Part III. Rate Schedule No. 20		
Title: PRIVATE LIGHTING (no new installations allowed)		PSC File Mark Only

NET MONTHLY RATE

Installed on existing Company owned poles and connected to existing Company owned overhead lines of adequate capacity and suitable voltage.

Rate Modifier	Description	kWh	Monthly Rate Per Lamp
	Mercury Vapor		
302*	8000 Lumen	68	$3.54
303**	8000 Lumen	68	$8.25

*On existing pole
**With Special Facilities

Special Facilities: The Company will extend its secondary conductor one span not to exceed 125 feet in length and/or install one 30 foot wood pole, including guy and anchor where needed, for support of such luminaire. Extension of special facilities will be limited to one span and/or one pole for each luminaire.

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-21.1 Sheet 1 of 3	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Lighting	
Part III. Rate Schedule No. 21		
Title: AREA LIGHTING (no new installations allowed)		PSC File Mark Only

AVAILABILITY

This rate is available to customers requesting outdoor area lighting service for apartment projects, subdivisions, mobile home parks, parking lots, parks and grounds around buildings to be served from Company electric supply lines of adequate capacity and suitable voltage available, and where all the Customer's electricity requirements were purchased from the Company. This rate is applicable to existing installations only, with no new installations allowed. As existing mercury vapor fixtures and/or ballasts need to be replaced on or after April 1, 2007, the Customer will have the option to transfer to another open tariff offering. As existing metal halide or high pressure sodium facilities need to be replaced and existing inventory is depleted, the Customer will have the option to transfer to another open tariff offering.

TYPE OF SERVICE

The Company will furnish, install, own, operate, and maintain a complete area lighting system of design and installation approved by the Company. The lights will be controlled to burn from dusk to dawn.

NET MONTHLY RATE

The Customer agrees to pay for service at the following rate:

Rate Modifier	Description	kWh	Monthly Rate Per Lamp
	Mercury Vapor		
322	100 Watt	42	$6.14
323	175 Watt	68	$6.19
324	250 Watt	98	$6.42
325	400 Watt	155	$6.45

ARKANSAS PUBLIC SERVICE COMMISSION

Rate Modifier	Description	kWh	Monthly Rate Per Lamp
	Mercury Vapor		
326	700 Watt	257	$6.45
327	1000 Watt	364	$9.51
	Metal Halide		
336	400 Watt	156	$6.29
337	1000 Watt	373	$7.87
	High Pressure Sodium		
350	70 Watt	35	$4.88
351	100 Watt	49	$4.90
352	250 Watt	105	$5.66
346	400 Watt	165	$6.27
347	1000 Watt	388	$8.19

Facilities Charge:

The Customer agrees to pay the following charge in addition to their monthly rate:

Mercury Vapor	1.46% per month of Company's investment that is in excess of $154 per lamp
Metal Halide & High Pressure Sodium	1.46% per month of the Company’s investment to provide the lighting system

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-22.1 Sheet 1 of 3	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Lighting	
Part III. Rate Schedule No. 22		
Title: OUTDOOR LIGHTING		PSC File Mark Only

AVAILABILITY

No new mercury vapor installations will be allowed on this schedule on or after April 1, 2007. As existing mercury vapor fixtures and/or ballasts need to be replaced on or after April 1, 2007, the Customer will have the option to transfer to anothepr open tariff offering.

This rate is available to customers requesting outdoor area lighting service for private lighting systems, apartment projects, subdivisions, mobile home parks, parking lots, parks and grounds around buildings to be served from Company electric supply lines of adequate capacity and suitable voltage available, and where all the Customer's electricity requirements were purchased from the Company.

TYPE OF SERVICE

The Company will furnish, install, own, operate, and maintain a complete area lighting system of design and installation approved by the Company. The lights will be controlled to burn from dusk to dawn.

The Customer agrees to provide all required right-of-way together with tree trimming permits for installation of the system, and to protect the Company’s equipment from damage.

The Company shall have the right to build pole line and install equipment upon the Customer’s property and shall have access to the Customer’s premises for any other purpose necessary for the performance of this service. The facilities installed by the Company will remain the property of the Company and may be removed by Company upon discontinuance of service.

The Company will exercise reasonable diligence at all times to furnish Customer service as contracted for, but will not be liable for damages caused by any interruption, deficiency or failure of service. The Company reserves the right to interrupt the service when such interruption is necessary for repairs to its lines or equipment or the safe operation of those facilities.

ARKANSAS PUBLIC SERVICE COMMISSION

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: Lighting

Part III. Rate Schedule No. 22

Title: OUTDOOR LIGHTING

PSC File Mark Only

NET MONTHLY RATE

The Customer agrees to pay for service at the following rate:

Rate Modifier	Description	kWh	Monthly Rate Per Lamp
	Mercury Vapor		
400	175 Watt	68	$6.19
401	400 Watt	155	$6.45
	Metal Halide		
402	400 Watt	156	$6.29
403	1000 Watt	373	$7.87
	High Pressure Sodium		
404	100 Watt	49	$4.90
405	250 Watt	105	$5.66
406	400 Watt	165	$6.27
407	1000 Watt	388	$8.19
	Light Emitting Diode		
LED 01	0 - 100 Watts - Less than 10,000 lumens	20	$3.68
LED 02	101-250 Watts - 10,000-25,000	56	$5.54
LED 03	Over 250 Watts - Over 25,000	100	$9.41

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ARKANSAS PUBLIC SERVICE COMMISSION

Facilities Charge:

1.46% per month of the Company’s investment to provide each lighting system.

Adjustments:
Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatthour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

REPLACEMENT, REMOVAL, OR DISCONNECT

When a customer requests that the Company replace an existing non-LED lighting system with an LED lighting system the customer may be required to pay to the Company a one-time Conversion Fee of $95.

When a customer requests that the Company disconnect or remove an existing LED lighting system the customer may be required to pay to the Company a one-time Removal Fee of $145.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-23.1 Sheet 1 of 1	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 23		
Title: Reserved for Future Use		PSC File Mark Only

This Schedule has been removed from the tariff book.

Reserved for Future Use

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ARKANSAS PUBLIC SERVICE COMMISSION

AVAILABILITY

This rider is available to Customers receiving electric service under the General Service (GS) or Lighting and Power Service (LP) Schedules having in regular use, permanently installed for heating either an electric reverse cycle central system heat pump or a total of 5 Kilowatts or more of electric devices used for comfort space heating. The installation must be verified by Company personnel.

Service under this rider is subject to all provisions of the applicable rate schedule to which it applies, except those provisions specifically modified herein.

APPLICABILITY

This rider will be applicable in any year when Company's May through September maximum monthly system peak demand exceeds the preceding October through April maximum monthly system peak demand by 20%.

KILOWATT CHARGE

During October through April billing cycles:

The Kilowatt charge will be computed using the Kilowatts of Billing Demand, which will be measured and will be the average kilowatt load used by the Customer during the 15-minute period of maximum use during the current month, but not to exceed the Kilowatts of Billing Demand established during the immediately preceding May through September billing cycles. However, the measured Kilowatts of Billing Demand for billing purposes will not be reduced by an amount greater than 60% of the kW load of the devices used for comfort space heating.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-25.1 Sheet 1 of 1	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 25		
Title: TAX ADJUSTMENT RIDER		PSC File Mark Only

ARTICLE I:

Availability
This tariff schedule provides for the Company to pass directly to its customers within a municipality the proportionate part of any franchise or street rental taxes levied or imposed on the Company by that municipality on gross revenues from those customers.

Application
There shall be shown as a separate line item on each monthly bill for electric service to customers located within a municipality the amount of any street rental or franchise tax imposed or levied on the Company by the municipality on the gross revenues derived from the sale of electric power and energy to customer within the city limits of such municipality.

ARTICLE II:

Availability
In addition to all other charges, the amount of the Customer's bill will be increased by applicable sales taxes and other charges made effective by duly constituted authorities having jurisdiction.

Application
Each monthly bill for electric service to customers will include the amount of any sales tax and other charges levied or imposed by duly constituted authorities having jurisdiction over the customer for their electric usage.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-26.1	Sheet 1 of 4
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 26		
Title: MUNICIPAL TAX RATES		PSC File Mark Only

	Tax Rate		
Municipality	Applicable To: Residential/Commercial	Industrial	Municipal
Ashdown	4%		
Avoca	2		
Bethel Heights	2		
Blevins	2		
Bonanza	4.25		
Booneville	3		
Cave Springs	3		
Centerton	4		
Cove	2		
DeQueen	4		
Dierks	4		
Elm Springs	4.25	4.25	
Eureka Springs	5		
Farmington	6		

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. R-26.2 Sheet 2 of 4

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: As Applicable

Part III. Rate Schedule No. 26

Title: MUNICIPAL TAX RATES

PSC File Mark Only

	Tax Rate		
Municipality	Applicable To: Residential/Commercial	Industrial	Municipal
Fayetteville	3	1	
Foreman	4		
Fouke	2		
Fulton	2		
Gillham	2		
Gravette	4	4	4
Greenland	2		
Greenwood	4.25		
Hackett	4.25		
Hartford	4.25		
Hatfield	2		
Horatio	4		
Huntington	4		
Johnson	4		

R-26 Muni Tax_02-01-2019 clean

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ARKANSAS PUBLIC SERVICE COMMISSION

Original — Sheet No. R-26.3 — Sheet 3 of 4

Replacing: — Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric — Class of Service: As Applicable

Part III. Rate Schedule No. 26

Title: MUNICIPAL TAX RATES

PSC File Mark Only

	Tax Rate		
Municipality	Applicable To: Residential/Commercial	Industrial	Municipal
Lincoln	4.25		
Little Flock	4	1	
Lockesburg	2		
Lowell	4	1	
Magazine	4.25		
Mansfield	4		
McCaskill	4.25		
Mena	4		
Midland	2		
Mineral Springs	4.25		
Murfreesboro	4.25	4.25	
Nashville	4.25		
Ogden	2		
Ozan	2		
Pea Ridge	4		

R-26 Muni Tax_02-01-2019 clean

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ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-26.4	Sheet 4 of 4
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 26		
Title: MUNICIPAL TAX RATES		PSC File Mark Only

Municipality	Tax Rate Applicable To: Residential/Commercial	Industrial	Municipal
Prairie Grove	4.25		
Rogers	4	1	
Springdale	4	1	
Texarkana	6	4	6
Waldron	4		
Washington	2		
West Fork	4.25		
Wilton	3		
Winthrop	2		

Note: Municipal Tax Amount is itemized on customer's bill as "MUNICIPAL FRANCHISE ADJ."

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-27.1	Sheet 1 of 12
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 27		
Title: ENERGY COST RECOVERY RIDER (RIDER ECR)		PSC File Mark Only

RECOVERY OF ENERGY COST

Energy Cost Recovery Rider ("Rider ECR ") defines the procedure by which the "Energy Cost Rate" of Southwestern Electric Power Company ("SWEPCO" or "Company") shall be initially established and periodically redetermined. The Energy Cost Rate shall recover the Company's net fuel and purchased energy cost, as defined in this Rider ECR.

ENERGY COST RATE

The Energy Cost Rate shall be redetermined annually through filings made in accordance with the provisions of Annual Redetermination of this Rider ECR. The Energy Cost Rate shall be applied to each customer's monthly billing energy (kWh). For electric service billed under applicable rate schedules for which there is no metering, the monthly usage shall be estimated by the Company and the Energy Cost Recovery Rider shall be applied. The Energy Cost Rate shall be calculated to the nearest $0.000001 and when applied to customers' bills shall be rounded to the nearest cent.

ANNUAL REDETERMINATION

On or before March 15 of each year the Company shall file a redetermined Energy Cost Rate with the Arkansas Public Service Commission (APSC or Commission). The redetermined Energy Cost Rate shall be determined by application of the Energy Cost Rate Formula set out in Attachment A of this Rider ECR. Each such revised Energy Cost Rate shall be filed in the proper underlying docket and shall be accompanied by a set of workpapers sufficient to fully document the calculations of the revised Energy Cost Rate.

The redetermined Energy Cost Rate shall reflect the projected Energy Cost for the 12-month period commencing on April 1 of each year ("Projected Energy Cost Period") together with a true-up adjustment reflecting the over-recovery or under-recovery of the Energy Cost for the 12-month period ended December 31 of the prior calendar year ("Historical Energy Cost Period"). The Energy Cost Rate so determined shall be effective for bills rendered on and after the first billing cycle of April of the filing year and shall then remain in effect for twelve (12) months, except as otherwise provided for below.

<u>The annual update shall include a report of the following:</u>

1. detailed fuel and purchased energy costs by FERC account and month for the historical year;
2. identify and explain changes from the prior year for major cost components of the ECR Rider, including fuel expense, purchased energy expense, off-system sales margins, etc., of 10% or more;
3. identify changes in accounting procedures affecting fuel and purchased power costs, such as changes in FERC account number classifications and changes in costing methodologies;
4. identify changes in fuel and purchased power procurement practices;
5. identify the monthly level of coal inventory in days and tons for the historical year;
6. identify the average price per unit for each fuel type and purchased power for the historical year;

7. identify revisions to the AEP System Integration Agreement affecting fuel and purchased energy costs;

8. identify and discuss changes in environmental regulations affecting fuel and purchased energy costs and explain the Company's plans for compliance;

9. identify plant outages for the historical year and explain the cause(s) of the outages; and

10. provide the summation of all day-ahead and real-time transactions, centered around the SPP energy market, and forward transactions, which will be made outside the SPP energy market beyond the day-ahead time horizon, including total shareholder off-system sales margin allocations, for each month in the preceding calendar year.

ADJUSTMENTS

If prior to the annual redetermination of the Energy Cost Rate, Staff or the Company becomes aware of an event that is reasonably expected to occur and/or has occurred which will materially impact the Company's Energy Cost, either the Staff or the Company may propose an adjustment to the Energy Cost Rate Formula set out in Attachment A of this Rider ECR. Furthermore, should a cumulative over-recovery or under-recovery balance arise during any Rider Cycle which exceeds ten percent (10%) of the Historical Energy Cost Period, then either the APSC General Staff ("Staff") or the Company may propose an interim revision to the then currently effective Energy Cost Rate.

PAYMENT FOR SERVICE

Payment for Service Rider – See Rate Schedule 44.

ATTACHMENT A

ENERGY COST RATE FORMULA

ECR = ENERGY COST RATE

$$ECR = \frac{(TUA + (PEC * JAF) + DEFCON + M)}{PES} * LCF$$

WHERE,

$$TUA = \sum_{j=1}^{12}\left(\left(EC_j * JAF\right) - \left(RR_j - PTU_j\right)\right) + CC_j$$

Where,

EC_j = *ENERGY COST FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD (1)*

$$EC_j = Fe_j + Pe_j - MST_j + AR\ ADJ_j - ALLOWREV_j$$

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Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 27		
Title: ENERGY COST RECOVERY RIDER (RIDER ECR)		PSC File Mark Only

ATTACHMENT A (continued)

Where

Fe_j = *FUEL EXPENSE CHARGED TO ACCOUNT 501 LESS ACCOUNT 501 COSTS THAT FIT THE DEFINITION OF FERC ACCOUNT 152 PLUS LIMESTONE, ACTIVATED CARBON, CALCIUM BROMIDE, HYDRATED LIME, AND UREA EXPENSE CHARGED TO ACCOUNT 502 PLUS SO_2 AND NO_X EMISSION COSTS CHARGED TO ACCOUNT 509, LESS FUEL, ENVIRONMENTAL CHEMICAL, AND EMISSION COSTS ASSOCIATED WITH OFF-SYSTEM SALES TRANSACTIONS IN MONTH j OF THE HISTORICAL ENERGY COST PERIOD (8,9,11)*

Pe_j = *PURCHASED <u>ENERGY</u> EXPENSE, CHARGED TO ACCOUNTS 555 (10), LESS FUEL COST ASSOCIATED WITH SALES TRANSACTIONS, IN MONTH j OF THE HISTORICAL ENERGY COST PERIOD, LESS THE CLECO PSSA PURCHASED ENERGY EXPENSE*

MST_j = *MARGINS FROM OFF-SYSTEM SALES TRANSACTIONS RECORDED IN MONTH j OF THE HISTORICAL ENERGY COST PERIOD (2)*

$AR\ ADJ_j$ = *ADJUSTMENT FOR REMOVAL OF TURK PLANT EXPENSES AND REVENUES BECAUSE THE TURK PLANT DOES NOT SERVE ARKANSAS LOAD (9)*

$ALLOWREV_j$ = *REVENUES ASSOCIATED WITH SALES OF SO_2 AND NO_X EMISSIONS ALLOWANCES RECORDED IN ACCOUNT 4118 AND REVENUES RECEIVED FROM THE SALE OF RENEWABLE ENERGY CREDITS,*

ATTACHMENT A (continued)

JAF = *JURISDICTIONAL ALLOCATION FACTOR (3)*

RR_j = *REVENUE UNDER RIDER ECR FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD*

PTU_j = *PRIOR PERIOD TRUE-UP ADJUSTMENT APPLICABLE FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD*

CC_j = *CARRYING CHARGES FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD*

$CC_j = (BB_j + EB_j)/2 * CCR * DAYS_j/365$

WHERE,

BB_j = *BEGINNING MONTH OVER/UNDER-RECOVERY BALANCE, EXCLUDING CARRYING CHARGES, FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD*

EB_j = *ENDING OVER/UNDER-RECOVERY BALANCE, EXCLUDING CARRYING CHARGES, FOR MONTH j OF THE HISTORICAL ENERGY COST PERIOD*

ATTACHMENT A (continued)

CCR = CARRYING CHARGE RATE (4)

$DAYS_j$ = NUMBER OF DAYS IN MONTH j OF THE HISTORICAL ENERGY COST PERIOD

PEC = ESTIMATED ENERGY COST FOR THE PROJECTED ENERGY COST PERIOD (5)

$$PEC = \sum_{j=1}^{12} EC_j$$

M = $7,487 OF PROJECTED FINAL MINE CLOSING AND RECLAMATION COSTS FOR SWEPCO'S PIRKEY POWER PLANT

LCF = LOSS CORRECTION FACTOR (6)

PES = PROJECTED SALES (kWh) SUBJECT TO THIS RIDER ECR FOR THE PROJECTED ENERGY COST PERIOD

DEFCON=AMORTIZATION OF DEFERRED CONSUMABLES ASSOCIATED WITH APSC DOCKET NO. 14-080-U

ATTACHMENT A (continued)

(1) The Historical Energy Cost Period is the calendar year immediately preceding the filing year.

(2) The margins from off-system sales transactions shall be treated in the following manner:

Customers shall be credited with 100% of the off-system sales margins allocated to SWEPCO's Arkansas retail jurisdiction up to $1,200,000 on an annual basis. For any off-system sales margins allocated to SWEPCO's Arkansas retail jurisdiction above $1,200,000, 90% of such margins shall be credited to customers and 10% of such margins shall be retained by the shareholders. Arkansas retail customers shall be shielded from any overall net annual loss from off-system sales transactions that may occur. In any year when the net margins from off-system sales result in a loss, such losses shall be borne by SWEPCO.

Treatment of Affiliated Sales Margins

Margins allocated to SWEPCO's Arkansas retail jurisdiction resulting from capacity sales will be reflected in the calculation of the Energy Cost Recovery Rider.

(3) The jurisdictional allocation factor will be derived in a two step process. First, for each jurisdiction the voltage level kWh at the meter will be divided by the most recent energy loss factors to determine the voltage level kWh at generation. Second, the Arkansas jurisdictional kWh at generation will be divided by the total kWh at generation for all jurisdictions less the Cleco PSSA kWh to develop the Arkansas jurisdictional allocation factor.

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ATTACHMENT A (continued)

(4) The Carrying Charge Rate shall be the Commission authorized interest rate on customer deposits.

(5) The Estimated Energy Costs for the Projected Energy Cost Period is equal to the energy costs for the Historical Energy Cost Period (the calendar year immediately preceding the filing year). Should there be unusual circumstances associated with any Projected Energy Cost or Projected Energy Cost Period either the Company or the Staff may propose use of a Projected Energy Cost (PEC variable) different from that defined by this formula.

(6) The loss correction factors will be determined by dividing the sum of the metered kWh sales for the Arkansas jurisdiction by the sum of the sales at the generation level for the Arkansas jurisdiction. This ratio of sales to generation is known as the "composite loss factor" for the Arkansas jurisdiction. The LCF for each voltage level is determined by dividing the service voltage loss factor by the composite loss factor.

(7) The deferred consumable balance under APSC Docket No. U-14-080-U as of the (insert date of new base rates) amortized over three years.

ATTACHMENT A (continued)

(8) Fuel Expense charged to Account 501 associated with the lignite supply to the Dolet Hills Power Plant will be treated in the following manner:

<u>Treatment of the Dolet Hills Lignite Company Expenses</u>

SWEPCO will be allowed to recover the costs associated with the Dolet Hills Lignite Company (DHLC) in the following manner:

Account 501 shall include costs associated with the DHLC mining operations in Month j of the Historical Energy Cost Period. DHLC services shall be provided at cost with the financing costs being calculated using the authorized rate of return on rate base most recently approved for SWEPCO by the APSC in a non-appealable final order on DHLC assets rather than DHLC's actual rate of return.

Production costs for DHLC shall be subject to the same ratemaking adjustments as applied to SWEPCO in a general rate case. Ratemaking adjustments shall include, but not be limited to:

- disallowance of charitable contributions and membership dues in civic organizations;
- disallowance of the portion of trade association memberships related to lobbying expenses and other disallowable costs;
- disallowance of expenses related to public relations advertising, image advertising, marketing, and corporate sponsorships;

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ATTACHMENT A (continued)

- 50/50 sharing of directors' and officers' liability insurance expense between ratepayers and shareholders;
- disallowance of long-term incentive compensation related to stock performance;
- 50/50 sharing of incentive compensation related to financial incentives for operations between ratepayers and shareholders; and
- disallowance or sharing of similar costs allocated to DHLC by SWEPCO or American Electric Power Service Corporation.

SWEPCO shall provide a report with its annual Rider ECR filing that identifies the total costs reflected in invoices from DHLC and the ratemaking adjustments made to arrive at the amounts included in Fuel Expense for the Historical Energy Cost Period in sufficient detail to identify the items disallowed.

(9) *AR ADJ*$_j$ as described in the definition above is an adjustment to Arkansas jurisdictional share of SWEPCO's total fuel cost for month (j). The detailed description of the adjustment effective with the implementation of the SPP IM is provided in the Direct Testimony and Exhibits of Naim Hakimi APSC Docket No. 14-022-TF, Page 9, Line 8 through Page 12, Line 6 and Exhibit ANH-4. The adjustment removes the Turk plant fuel cost (including related NO_x and SO_2 emissions costs) and associated revenues from sale of the Turk plant output in the SPP market from the Energy Cost.

ATTACHMENT A (continued)

(10) The recovery of energy costs associated with long-term renewable energy resources must be approved by the Commission prior to the recovery of costs through Rider ECR.

(11) No charges for activated carbon, calcium bromide, hydrated lime, or urea may be passed through the rider to customers unless the Commission has approved the prudence of the particular environmental controls project at issue or the Commission has otherwise approved the recovery of the costs for such a project in retail rates. Pursuant to Order No. 1 of Docket No. 14-080-U, SWEPCO shall defer the cost of activated carbon, calcium bromide, hydrated lime, and urea associated with the Dolet Hills and Pirkey power plants for serving Arkansas retail load incremental to the amount of chemical costs embedded in Arkansas retail rates without carrying charges.

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Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 28		
Title: Supplementary, Backup, Maintenance, and As-Available Standby Power Service		PSC File Mark Only

AVAILABILITY

This schedule is available for Supplementary, Backup, Maintenance and As-Available Standby Power to customers that own and operate power production equipment or other source of power not held primarily for emergency use and that have a separate agreement for interconnection to Company's system stating those terms and conditions.

Service will be supplied at one point of delivery at locations where facilities of adequate capacity and suitable phase and voltage are available. Service may be provided on the Company's standard Contract for Electric Service, containing the Standard Terms and Conditions, stating the rate applicable to Supplementary Power and Energy, the Supplementary Power Contract Demand, the Backup Power Contract Demand, the Maintenance Power Contract Demand and the As-Available Standby Power Contract Demand that the Company is obligated to provide. The rate applicable to Supplementary Power and all energy is limited to the Lighting and Power Service Rate (LP), the Large Lighting and Power Service Rate (LLP), or the Pulp and Paper Mill Rate (P&PM), whichever is applicable. When used in conjunction with the Pulp and Paper Mill Rate, the Pulp and Paper Mill Rate will apply only to the Supplementary Power and all energy.

DEFINITIONS

Supplementary Power is electric capacity supplied by the Company, regularly used by a Customer in addition to that which the Customer's generation facility regularly generates. The Supplementary Power Billing Demand shall be determined in the Supplementary Power Charge section of this tariff.

Maintenance Power is electric capacity supplied by the Company during scheduled outages of the Customer's facility to replace capacity which is ordinarily generated by the Customer's own generation. This capacity when supplied during each of the months of October through May to Customers with total generating capacity of less than 5,000 kW shall be considered to be scheduled and approved by the Company as Maintenance Power until such time as the aggregate generation of all customer owned sources of power which are connected to the Company exceed 1% of the Company's peak system load. Customers with total generation capacity of 5,000 kW or greater must obtain written Company approval at least seven days in advance for a scheduled outage during the months of October through May or the use of capacity will be considered to be Supplementary Power. Maintenance Power will be supplied at the sole discretion of the Company, provided the

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Company is reasonably certain that a system peak will not be created during this period and providing the Company, in its judgment, has adequate capacity in its own system to supply the requested demand. Maintenance Power will normally not be available during the months of June through September.

Maintenance Power Demand is the Kilowatts of Billing Demand that exceed the Supplementary Power Billing Demand during the period approved for maintenance power usage. If As-Available Standby Power has been requested during this period, then for billing purposes, the Maintenance Power Demand will be equal to the Maintenance Power Contract Demand.

Backup Power is electric capacity supplied by the Company during an unscheduled outage of the Customer's facility to replace capacity ordinarily provided by the Customer's own generation. However, any capacity supplied by the Company during an unscheduled outage of the Customer's facility to replace that which is ordinarily provided by the Customer's own generation during the months of June through September shall be considered as Backup Power, and/or As-Available Standby Power if approved by the Company. The Customer shall notify the Company's system dispatcher as soon as reasonably possible when requesting the initiation and termination of Backup Power. The customer shall also provide written documentation to the Company within 24 hours or on the first working day following a weekend or holiday confirming the date and time of both the initiation and termination of Backup Power.

Backup Power Demand is the Kilowatts of Billing Demand that exceed the Supplementary Power Billing Demand during the period of Backup Power usage. If As-Available Standby Power has been requested during this period, then for billing purposes, the Backup Power Demand will be equal to the Backup Power Contract Demand.

Kilowatts of Billing Demand for each month will be the average kilowatt load used by the Customer during the 15-minute period of maximum use during the month.

As-Available Standby Power is electric capacity supplied by the Company during a scheduled or unscheduled outage of the Customer's facility to replace capacity which is provided by the Customer's own generation. Customer may request As-Available Standby Power at any time subject to the conditions specified herein. However, the Customer must request and receive prior approval from Company each time As-Available Standby Power is required and must also notify the Company

when As-Available Standby Power is to be discontinued. When Customer experiences a forced outage of his power production facilities, Customer must request approval from Company's dispatcher for continued use of As-Available Standby Power after the forced outage has occurred and use of As-Available Standby Power has begun. This provision for after-the-fact request and approval shall apply only if Customer has contacted the Company's system dispatcher for approval as soon as reasonably possible. All requests for and terminations of As-Available Standby Power shall be confirmed in writing to the Company by the Customer within 24 hours of the request or termination. As-Available Standby Power will be available solely at the discretion of the Company. At the request of Company, the Customer will cease use of As-Available Standby Power within ten (10) minutes after notification from the Company that approval for continued use of that As-Available Standby Power is denied. Use of As-Available Standby Power will be subject to immediate interruption for emergency system conditions.

As-Available Standby Power Demand is the kilowatts of capacity requested by the Customer. This capacity is requested in addition to any capacity associated with Supplementary, Backup, or Maintenance Power during the period of Backup or Maintenance Power usage.

MONTHLY RATE

The monthly billing shall be the sum of the following:

(I) Supplementary Power Charge
(II) Backup Power Charge and Maintenance Power Charge
(III) As-Available Standby Power Charge
(IV) Energy Charge

(I) SUPPLEMENTARY POWER CHARGE

The applicable rate schedule for supplementary power, with modifications to the provisions for the Determination of Kilowatts of Billing Demand and the Power Factor Adjustment, as specified herein, will be applied to any and all electric capacity actually supplied by the Company during the month, except for any Maintenance Power Demand, any Backup Power Demand, and any As-Available Standby Power Demand.

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Determination of Supplementary Power Billing Demand

When neither Backup, Maintenance, nor As-Available Standby Power are being used, the Supplementary Power Billing Demand will be the Kilowatts of Billing Demand established by the Customer, subject to the Kilowatts of Billing Demand provisions specified in the Lighting and Power Rate, the Large Lighting and Power Rate, or the Pulp and Paper Mill Rate, whichever is applicable. When Backup, Maintenance, or As-Available Standby Power is taken in conjunction with Supplementary Power, the Supplementary Power Billing Demand will be the greatest of:

A. Supplementary Power Contract Demand as specified in the Contract for Electric Service;
B. The Kilowatts of Billing Demand less the Backup Power Contract Demand when Backup Power is being used, less the Maintenance Power Contract Demand when Maintenance Power is being used, less the As-Available Standby Power Demand requested;
C. Supplementary Power Billing Demand of the current month;
D. Seventy percent (70%) of the highest Supplementary Power Billing Demand of the previous eleven months for customers receiving service under the LP rate schedule, eighty percent (80%) of the highest Supplementary Power Billing Demand of the previous eleven months for customers receiving service under the LLP rate schedule, or the highest Supplementary Power Billing Demand in the 12-month period ending with the current month for customers receiving service under the P&PM rate schedule.

(II) BACKUP POWER CHARGE AND MAINTENANCE POWER CHARGE

The monthly billing for Backup Power and Maintenance Power shall be the sum of (A) the Backup Power Charge, plus (B) the Maintenance Power Charge. However, this amount shall not be less than (C) the Minimum Monthly Charge for Backup Power and Maintenance Power.

(A) BACKUP POWER CHARGE

Company agrees to supply Backup Power up to but not exceeding the Backup Power Contract Demand. The Backup Power Contract Demand shall not exceed the nameplate rating of the Customer's generating unit(s) unless the Customer can demonstrate a higher capability for its unit(s). The Backup Power Contract Demand can be adjusted annually with written request by the Customer and with written consent of the Company.

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Part III. Rate Schedule No. 28		
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Daily Rate for Backup Power

The Daily Rate for Backup Power will be the Kilowatts of Backup Power Demand times the applicable rate:

Pulp & Paper Mill Transmission Service	$0.31
Large Lighting & Power Transmission Service	$0.31
Lighting & Power Primary Service	$0.46
Lighting & Power Secondary Service	$0.50

(B) MAINTENANCE POWER CHARGE

The Company agrees to supply Maintenance Power up to but not exceeding the Maintenance Power Contract Demand. Maintenance Power Contract Demand shall not exceed the nameplate rating of the Customer's generating unit(s) unless Customer can demonstrate a higher capability for its unit(s). The Maintenance Power Contract Demand can be adjusted annually with written request by the Customer and with written consent of the Company. Upon approval by the Company, Maintenance Power may be scheduled for a total of three occurrences in a calendar year during the months of January through May and October through December for each of the Customer's generating unit(s) provided Customer provides the Company at least seven days prior notice of intent to perform maintenance. In the event maintenance exceeds the scheduled time period provided by the Customer and agreed to by the Company or exceeds a maximum of 30 days per generating unit per calendar year, unless it is agreed to extend Maintenance Power or supply Backup Power, by written request by the Customer and written consent of the Company, such excess use of capacity will be billed as Supplementary Power.

Daily Rate for Maintenance Power

The Daily Rate for Maintenance Power will be the Kilowatts of Maintenance Power Demand times the applicable rate:

Pulp & Paper Mill Transmission Service	$018
Large Lighting & Power Transmission Service	$0.18
Lighting & Power Primary Service	$0.18
Lighting & Power Secondary Service	$0.22

(C) MINIMUM MONTHLY CHARGE FOR BACKUP POWER AND MAINTENANCE POWER

The Minimum Monthly Charge for Backup Power and Maintenance Power shall be the applicable monthly rate per kW of Backup Power Contract Demand plus the applicable monthly rate per kW of Maintenance Power Contract Demand in excess of the Backup Power Contract Demand.

Backup Power - Minimum Charge Per kW:

Pulp & Paper Mill Transmission Service	$1.33
Large Lighting & Power Transmission Service	$1.33
Lighting & Power Primary Service	$4.23
Lighting & Power Secondary Service	$4.42

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Maintenance Power - Minimum Charge Per kW:

Pulp & Paper Mill Transmission Service	$0.68
Large Lighting & Power Transmission Service	$0.68
Lighting & Power Primary Service	$2.11
Lighting & Power Secondary Service	$2.22

(III) AS-AVAILABLE STANDBY POWER CHARGE
The Company agrees to supply As-Available Standby Power up to but not exceeding the As-Available Standby Power Contract Demand. The As-Available Standby Power Contract Demand shall not exceed the nameplate rating of the Customer's generating unit(s) unless the Customer can demonstrate a higher capability for its unit(s). The As-Available Standby Power Contract Demand can be adjusted annually with written request by the Customer and with written consent of the Company.

Monthly Rate for As-Available Standby Power
The monthly rate for As-Available Standby Power will be the As-Available Standby Power Demand times the applicable rate:

Pulp & Paper Mill Transmission Service	$0.47
Large Lighting & Power Transmission Service	$0.47
Lighting & Power Primary Service	$1.96
Lighting & Power Secondary Service	$2.04

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(IV) ENERGY CHARGE
The monthly rate for all energy used during the month will be the kilowatt-hour charge as set forth in the Lighting and Power Rate, Large Lighting and Power Rate, or Pulp and Paper Mill Rate, whichever is applicable.

Power Factor Adjustment - Kilovar Charge
The kilovars of Reactive Demand will be recorded each month by the Company and will be the average kilovars used by the Customer during the 15-minute period of maximum kilovar use during the month. A Generation Function Charge of $0.54 per month shall be made for each Kilovar of Reactive Demand exceeding 50% of the Kilowatts of Billing Demand.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service provided under the terms of this tariff will be furnished under the Company's Standard Contract containing the Standard Terms and Conditions and will be recognized as an exemption to the Exclusive Service Clause of the Company's Standard Terms and Conditions.

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Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 29		
Title: CHARGES FOR SPECIAL OR ADDITIONAL FACILITIES		PSC File Mark Only

In the event facilities in excess of a normal installation are found to be required to serve the Customer's load, or are requested by the Customer and approved by the Company, the Company shall furnish, install, and maintain such facilities with a monthly charge to the Customer according to the following schedule:

1. A monthly charge of 1.46% will be applied to the total investment in facilities that are installed, owned, operated and maintained by the Company.

2. The monthly charge rate for maintaining facilities installed and owned by the Company but for which Customer has paid the full amount to Company will be 0.69% of the total investment in the facilities.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under Company's Standard Terms and Conditions.

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Part III. Rate Schedule No. 30		
Title: TEMPORARY SERVICE		PSC File Mark Only

Service furnished for loads that are of a temporary nature, such as construction power, asphalt batch plants, carnivals, temporary commercial and industrial establishments, and others, will be billed on the applicable rate and the Customer will pay the Company the cost of installation and removal labor and unsalvageable materials including overhead costs.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under Company's Standard Terms and Conditions.

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Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 31		
Title: CHARGES RELATED TO CUSTOMER ACTIVITY		PSC File Mark Only

TERMS AND CONDITIONS

Services under this tariff are provided in accordance with the Company's Standard Terms and Conditions.

CHARGES RELATED TO CUSTOMER ACTIVITY

Customer Account Record Statement (General Service Rule (GSR) 2.04.A.)
The Company will charge a fee of: -- No Charge
when a customer or any authorized party requests a statement of the customer’s account record as described by GSR 7.02.

Energy Consumption Statement (GSR 2.04.B.)
The Company will charge a fee of: -- No Charge
when a customer or any authorized party requests a statement of the customer’s energy consumption for the preceding 13 months.

Deposit From Applicant (GSR 4.01.A. & B.)
The Company may require a deposit from any applicant to guarantee payment for service, subject to the conditions of GSR 4.01 in Subsections A. & B.

Deposit From Landlord (GSR 4.01.A. & B.(1))
The Company may require a deposit when an applicant for residential service qualifies as a landlord as defined in the APSC General Service Rules. The amount of the deposit will be calculated in accordance with GSR 4.01.B(1).

Deposit From Customer (GSR 4.02.A. & B.)
The Company may require a deposit from a customer when that customer meets the criteria in GSR 4.02.A.

The amount of the deposit will be calculated in accordance with GSR 4.02.B.

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Original	Sheet No. R-31.2	Sheet 2 of 4	
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Part III. Rate Schedule No. 31			
Title: CHARGES RELATED TO CUSTOMER ACTIVITY			PSC File Mark Only

<u>Processing Fee For Levelized Billing Withdrawal (GSR 5.10.C(3))</u>
The Company will require payment of a processing fee of: -------------------------- No Charge
if a customer withdraws from a levelized billing plan more than one time in 12 months.

<u>Returned Check Charge (GSR 5.13.)</u>
The Company will charge a returned check fee when a customer pays by check and the check is returned to the Company for any reason other than bank error. ---------$25.00

<u>Meter Reading Report Charge (GSR 5.16.B(3))</u>
The Company will charge a meter reading report fee of: -------------------------- No Charge
if a customer has requested a meter reading report in writing and the customer has already received two free meter reading reports in the last 12 months.

<u>Meter Test Fee (GSR 5.18.C.(1))</u>
The Company will charge a meter test fee when a customer's meter has been tested in accordance with the procedures set out in GSR 5.18., and the meter test results show the meter to be operating within the guidelines of Rule 7.05. of the Special Rules - Electric.

Self Contained ---$35.00
Other ---$59.00

<u>Collection Fee (GSR 6.11.)</u>
The Company will charge a fee when the last day to pay, as printed on the most recent cut-off notice, has passed and a utility employee accepts payment at the premises under GSR 6.09.B(1) without service being disconnected. -----------$10.00

Reconnection Fee (GSR 6.12.)

The Company will charge a reconnect fee when a customer or other authorized party requests reconnection during normal working hours, and payment is made at a Company business office or payment agency before the Company's close of business on the same day. --$25.00

The Company will charge a reconnect fee when a customer or other authorized party requests reconnection on a pole during normal working hours, and payment is made at a Company business office or payment agency before the Company's close of business on the same day. --$74.00

Finance Charge on Delayed Payment Agreements (GSR 6.13.I)

The finance charge on delayed payment agreements will be interest as defined by the GSR. ---No Charge
(The rate is set annually by the Commission.)

Meter Tampering

The Company will charge a fee if customer connects a meter that has been cut off by Company.

During regular working hours---$75.00

During other than regular working hours--$97.00

The Company will charge a minimum fee for a broken meter seal and/or meter tampering. ---$57.00

Connection Other Than Regular Working Hours

The Company will charge a fee for initiation of permanent service (if no construction is required) during other than regular working hours. ------------------$57.00

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Part III. Rate Schedule No. 31		
Title: CHARGES RELATED TO CUSTOMER ACTIVITY		PSC File Mark Only

Re-fusing Customer's Circuits
The Company will charge a service charge plus the price of fuses for re-fusing customer's circuits. ---$42.00

Faulty Customer-Owned Equipment
A service charge will be charged during regular business hours where trouble is found to be in customer's equipment. ---$82.00

A service charge will be charged after regular business hours where trouble is found to be in customer's equipment. ---$106.00

Relocation Fee
A facilities relocation fee (actual cost of labor and materials used) will be charged to customers requesting the relocation of Company's facilities. ----------Actual Cost

Translation and Non-Standard Reports (minimum charge)
The Company will charge a fee each time the Company provides meter pulse translation and any non-standard reporting requested by the customer. -----------------$25.00

Connect Fee
The Company will charge a fee each time a meter must physically be re-set or pulled and re-set. This fee does not apply to connects requiring only a read-out/read in. ----$10.00

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

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OPTION 1

Availability

This Option 1 is only available to customers receiving electric service under the Lighting and Power Service (LP) or Large Lighting and Power Service (LLP) rate schedules. Option 1 is available to new loads of 500 kW or more, or significant expansions of existing load in excess of 500 kW incremental load, or for resumption of service to loads of a minimum of 500 kW which have been inactive for 12 months or more. Service under Option 1 is available only in conjunction with a contract for electric service having a minimum initial term of five years and requiring a minimum of thirty (30) days advance notice to cancel thereafter.

To qualify for Option 1, the customer must furnish to the Company an affidavit stating that this rider was an important factor in the customer's decision to add new or incremental load or to resume load that has been inactive for 12 months or more, and complete and sign the appropriate application form.

The load factor of the entire facility, including expansion, must be equal to or greater than 40%.

The availability of Option 1 is at the sole discretion of the Company. The Company will not accept new applications for service under Option 1 when the Company's forecasts indicate that additional generating capacity will be needed within a three-year period.

All provisions of the LP or LLP rate schedules, whichever is applicable, will apply except as modified herein.

Definition of Base Period
The Base Period shall be the 12 months immediately preceding the month that service is requested under this rider, or as mutually agreed upon by the Company and the Customer.

Determination of Base Threshold Demand
For expansions, the Base Threshold Demand shall be determined based on the Kilowatts of Billing Demands of the Base Period. For new Customers or for Customers resuming service to loads which have been inactive for 12 months or more, the Monthly Base Threshold Demand shall be 0 kW. The Kilowatts of Billing Demand for each month of the Base Period may be adjusted as mutually agreed upon by the Company and the Customer to reflect the Customer's normalized load profile.

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Determination of Economic Development Demand

The Economic Development Demand subject to the provisions of Option 1 shall be that portion of the Kilowatts of Billing Demand during the current month that is greater than the Monthly Base Threshold Demand.

Determination of Economic Development Credits

The Customer's monthly bill for service under Option 1 will be calculated in accordance with the LP or LLP rate schedule, whichever is applicable, with the exception that an Economic Development Credit will be applied. An Economic Development Credit will be determined by multiplying the Economic Development Demand times the Kilowatt Charge of the LP or LLP rate schedule, whichever is applicable, times the appropriate Billing Credit Factor. The Billing Credit Factors are provided below:

Term of Economic Development Credit	Billing Credit Factors
Year 1 - First 12 monthly billing periods	50%
Year 2 - Next 12 monthly billing periods	40%
Year 3 - Next 12 monthly billing periods	30%

Special Terms and Conditions

In the event the monthly Kilowatts of Billing Demand for 12 consecutive months is less than the corresponding Base Threshold Demand, this rider will automatically terminate. Billing for subsequent months will revert to the LP or LLP rate schedule, whichever is applicable.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

OPTION 2

Availability

This Option 2 is only available to customers receiving electric service under the Lighting and Power (LP) rate schedule. Option 2 is available to new loads of 200 kW or more. Service under Option 2 is available only in conjunction with a contract for electric service having a minimum initial term of five years and requiring a minimum of thirty (30) days advance notice to cancel thereafter.

Examples of businesses and industries eligible for service under Option 2 include the following categories:

Distribution centers
Startup manufacturing
Big Box and/or retail stores
Server farms and other information technology related companies
Printing companies

To qualify for Option 2, the customer must furnish to the Company an affidavit stating that this rider was an important factor in the customer's decision to add load and complete and sign the appropriate application form.

The load factor of the facility must be equal to or greater than 40%.

The availability of Option 2 is at the sole discretion of the Company. The Company will not accept new applications for service under Option 2 when the Company's forecasts indicate that additional generating capacity will be needed within a three-year period.

All provisions of the LP rate schedule will apply except as modified herein.

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Original	Sheet No. R-32.4	Sheet 4 of 4
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 32		
Title: EXPERIMENTAL ECONOMIC DEVELOPMENT RIDER		PSC File Mark Only

Determination of Base Threshold Demand
The Monthly Base Threshold Demand shall be 0 kW.

Determination of Economic Development Demand
The Economic Development Demand subject to the provisions of Option 2 shall be that portion of the Kilowatts of Billing Demand during the current month that is greater than the Monthly Base Threshold Demand. The Economic Development Demand will not exceed 500 kW.

Determination of Economic Development Credits
The Customer's monthly bill for service under this rider will be calculated in accordance with the LP rate schedule with the exception that an Economic Development Credit will be applied. An Economic Development Credit will be determined by multiplying the Economic Development Demand times the Kilowatt Charge of the LP rate schedule times the appropriate Billing Credit Factor. The Billing Credit Factors are provided below:

Term of Economic Development Credit	Billing Credit Factors
Year 1 - First 12 monthly billing periods	35%
Year 2 - Next 12 monthly billing periods	25%
Year 3 - Next 12 monthly billing periods	15%

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

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Original	**Sheet No:** R-33.1	Sheet 1 of 4
Replacing:	**Sheet No:** R-33.1	
Name of Company: SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	**Class of Service:** As Applicable	
Part III. Rate Schedule No. 33		
Title: PURCHASED POWER SERVICE (PPS)		

PSC File Mark Only

AVAILABILITY

This rate shall apply to purchases by the Company of energy generated by qualified small power production and cogeneration facilities. The Qualified Facility's (QF) electrical requirements supplied by the Company shall be separately metered and billed in accordance with the applicable rate schedule. The rules under which small power production and cogeneration facilities can obtain qualifying status are defined in the Arkansas Public Service Commission Cogeneration Rules as approved. The design capacity of the qualified facility must be 100 kW or less.

PAYMENT SCHEDULE

The payment shall be the algebraic sum of calculations made under (I) and (II) below.

(I) RATE

(A) QF Charge (Payable by QF)

(1) Each QF will pay any interconnection costs which are defined as the costs of connection, switching, metering, transmission, distribution, safety provisions, and administrative costs incurred by the Company directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations. Interconnection costs do not include any costs included in the calculation of avoided costs in Section (I)(B). The QF will either make an initial payment to the Company for the interconnection costs for investment in facilities as determined above or make periodic payments over a two year period wherein such payments provide for the amortization of interconnection costs, as well as a return to the Company equal to its pre-tax

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marginal cost of capital. In addition, the QF will pay the monthly charge for maintaining facilities currently at the filed rate of 0.69 percent of the interconnection cost for investment in facilities as determined above.

(2) Monthly QF Charge (Payable by QF)
Each QF will pay a monthly QF Charge of $12.00. This charge is to cover such items as customer accounting expenses, administrative expenses, and general expenses incurred in servicing the QF.

(B) Monthly kWh Payment (Payment by Company)
Payment for energy delivered into Company's system with adjustment as provided in (II) will be at the following purchase rate:

Months – 2019	cents/KWH
1st Quarter - January, February, March	3.1164
2nd Quarter - April, May, June	2.4095
3rd Quarter - July, August, September	2.7714
4th Quarter - October, November, December	2.3866

Purchase rate will begin upon approval of the Purchased Power Service (PPS) rate schedule and will be revised no less frequently than annually.

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(II) ADJUSTMENTS

(A) (Meter readings may be made in conjunction with regular meter reading schedules. The actual metered kilowatt-hours will be billed according to the pricing period defined in (I)(B). Kilowatt-hour payments will be prorated to reflect the number of days within each quarter and each pricing period when metering does not allow for an actual determination.

BILLING

The Company shall send a statement to the QF on or before the 10th day after the QF's meter is read. The statement will show the kilowatt capacity, if any, and kilowatt-hours delivered to the Company during the period, customer charges payable to the Company, and total amount due. Payments for service will be rendered monthly, unless otherwise specified. The term "month" for payment purposes will mean the period between any two consecutive readings of the meters by the Company, such readings to be taken as nearly as practical every 30 days. The Company reserves the right to credit purchase of power against billings for electric service due and payable to the Company by the QF.

CONTRACT PERIOD

A Power Purchase Contract will be in effect for each service at each separate location. The Contract Period shall be negotiated between the QF and the Company. The Company's TERMS AND CONDITIONS FOR PURCHASE BY THE COMPANY OF ELECTRICITY APPLICABLE TO RATE SCHEDULE PURCHASED POWER SERVICE (PPS) are applicable to this rate schedule.

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Original	**Sheet No:** R-33.4	Sheet 4 of 4
Replacing:	**Sheet No:** R-33.4	
Name of Company: SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	**Class of Service:** As Applicable	
Part III. Rate Schedule No. 33		
Title: PURCHASED POWER SERVICE (PPS)		

PSC File Mark Only

SUPPLEMENTARY POWER SERVICE

Supplementary power is electric energy or capacity used regularly by a facility in addition to that power which it ordinarily generates for its own use. QF's electrical requirements for supplementary power service will be supplied by the Company and shall be separately metered and billed in accordance with the applicable rate schedule and the Company's Standard Terms and Conditions.

THIS SPACE FOR PSC USE ONLY

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Original	Sheet No. R-34.1	Sheet 1 of 1
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 34		
Title: REDUNDANT SERVICE POLICY FOR MUNICIPAL ACCOUNTS		PSC File Mark Only

AVAILABILITY

Redundant service is defined as those facilities, including metering equipment, to provide electric power and energy from an alternate source to municipal accounts served by the Company that require such redundant service.

APPLICABILITY

The kilowatt-hours used on the meter for redundant service plus the kilowatt-hours equal to the redundant transformer no load losses at 100% voltage shall be added to the kilowatt-hours used on the regular meter (for billing on the appropriate rate) plus a charge computed according to one of the following Alternatives:

ALTERNATIVE 1 For Total Company Investment to Provide Redundant Service

There will be a charge each month equal to 1.46% (17.52% per year) of the Company investment, which includes metering costs, to provide redundant service.

ALTERNATIVE 2 For Customer’s Contribution of the Total Investment to Provide Redundant Service

There will be a charge each month equal to 0.69% (8.28% per year) of the Customer's contribution of the total investment to provide redundant service.

ALTERNATIVE 3 For the Customer Desiring to Make a Contribution in Aid of Construction Toward the Investment Required to Provide the Redundant Service

There will be a charge each month equal to 1.46% (17.52% per year) of the Company’s investment, which includes metering costs, to provide redundant service plus a charge each month equal to 0.69% (8.28% per year) of the Customer's contribution toward the investment required to provide the redundant service.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under Company's Standard Terms and Conditions.

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Original	Sheet No. R-35.1	Sheet 1 of 2
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 35		
Title: EXTENSION OF FACILITIES AGREEMENT		PSC File Mark Only

For Residential Customers in Undeveloped Areas:

Southwestern Electric Power Company's (SWEPCO) philosophy is to extend facilities to provide service requested under the applicable rate schedule. If the anticipated continuing annual revenue, not including adjustment charge of fuel and tax adjustment charge, will not support the allocated portion of SWEPCO's investment in facilities to extend or provide service in undeveloped areas, the following extension policy will apply.

When the revenue from the prospective customer(s) does not meet these estimated criteria, the Company will be authorized to collect a minimum bill which will be determined by such factors as: cost of extension (not including system investment and cost of meter), growth potential, future earnings, system improvements, terrain, geography and other considerations.

The customer will be billed for electric service made available hereunder on the published rate schedule applicable to the location. However, for the amount of investment determined by the Company, customer agrees to pay the Company a minimum amount of $________ per month (1/60th of the allocated portion of SWEPCO's investment) plus the fuel adjustment charge and the tax adjustment charge as provided in the rate schedule for a period of five years from the date service is first made available to the customer from said extension. The customer agrees to pay said minimum monthly amount to the Company. Customer further agrees to pay said minimum monthly amount even though it may be in excess of the amount specified in Company's applicable published rate schedule. If the premises served under this agreement are sold, leased, or rented, the customer nevertheless guarantees the payment of said minimum bill for said period, as provided above.

For Industrial, Large Commercial and Loads Requiring an Unusual Amount of Investment

SWEPCO will own, install, operate and maintain the facilities required to supply the customer's electric requirements. Electric service will be furnished according to terms of a contract between the parties including the applicable rate schedule plus a provision which will provide:

In consideration of the determined investment in facilities by SWEPCO necessary to make electric service available, the customer agrees to pay to SWEPCO each month an amount, computed under the applicable rate schedule not including tax adjustment charge, the cost of fuel and/or fuel adjustment revenue, not less than 1/60th* of the determined investment required to supply the customer's electrical requirements. The determined investment will include such factors as cost of extension (including system investment), growth potential, future earnings, system improvements, terrain, geography and other considerations.

*The denominator of this fraction is to be the number of months for which service is contracted if less than 60 months.

Contribution in Aid of Construction

The customer may reduce the minimum bill requirement by making a contribution in aid of construction to reduce the determined investment to not more than five times the anticipated continuing annual revenue, not including the fuel adjustment charge and tax adjustment charge.

Contributions in aid of construction that are considered taxable income by a governmental agency or body will be increased by the approximate tax rate.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under Company’s Standard Terms and Conditions.

AVAILABILITY

This Rider is available only in conjunction with Company's Lighting and Power (LP) or Large Lighting and Power (LLP) rate schedules to Customers who contract for not less than 500 kW of curtailable power. The applicable rate schedule will be determined based on the Customers Total kW. All provisions of the Lighting and Power or Large Lighting and Power rate schedules, whichever is applicable, will apply except as modified herein. Service must be taken at one point of delivery and measured through one meter. This Rider is not available for backup power to customer owned generation. This Rider is not applicable in conjunction with Company's Experimental Economic Development Rider for loads designated as Curtailable kW.

The availability of service under this Rider is subject to the Company, in its sole judgment, having sufficient capacity and fuel to serve the requirements of its other customers and to maintain its spinning reserve. The availability of total system curtailable and interruptible kW contracted may be limited by the Company to an amount not to exceed 5% of the projected aggregate Company peak demand. Service is available under this Rider only if the utilization of such service is of such character that service can be curtailed at any time by Company, following 10 minutes notice by Company to Customer that service must be curtailed, without loss to Customer or damage to property or persons and without adversely affecting the public health, safety, and welfare.

DEFINITION OF TERMS

Total kW: Total kW is defined as the sum of the Firm kW and the Curtailable kW designated by the customer when contracting for service under this Rider and will be used to determine the applicable rate schedule.

Firm kW: Firm kW is defined as that portion of the Total kW that is not subject to curtailment under the terms and conditions of this Rider. The Firm kW will be designated by the Customer when contracting for service under this Rider. In addition, Firm kW may be adjusted annually by the Customer by written request to the Company.

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Original	Sheet No. R-36.2 Sheet 2 of 5	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 36		
Title: EXPERIMENTAL CURTAILABLE SERVICE RIDER		PSC File Mark Only

Curtailable kW: Curtailable kW is defined as that portion of the Total kW subject to curtailment by the Company under this Rider. The Curtailable kW will be designated by the Customer when contracting for service. In addition, Curtailable kW may be adjusted annually by the Customer by written request to the Company.

CONDITIONS OF SERVICE

Customer may choose to have Total kW or some portion thereof designated as Curtailable kW. The amount of Total kW not designated as Firm kW shall constitute Customer's Curtailable kW. Customer's service must be equipped, at Customer's expense, with devices necessary to reduce Total kW during the period of curtailment to Firm kW or below and with metering devices necessary to verify that Total kW is at or below the Firm kW. In addition, the Company may request that the Customer's service be equipped, at Customer's expense, with communication equipment necessary to provide instantaneous load information to Company's designated system operating center.

Company will request curtailment of electric service under this Rider as the Company deems necessary for any reason including, but not limited to, maintaining service to firm loads, avoiding establishment of a new system peak, avoiding establishment of a peak demand in excess of 95% of the Company's forecasted peak load for the year, maintaining service integrity in the area, or other situations when reduction in load on the Company's system is warranted. To the extent possible, curtailable loads served under this Rider will be curtailed before any curtailment of firm loads is requested or required. Requests for curtailment will be made by Company's System Operator via telephonic communication to Customer's designated representative(s). Upon application for service under this Rider, Customer shall designate the representative(s) and provide the telephone number at which they may be reached 24 hours a day. In the event of a curtailment for non-emergency purposes, Company will endeavor to provide notice to Customer at least 30 minutes prior to curtailment. In the event of a curtailment for emergency conditions, Company will attempt to provide as much prior notice as possible but is in no way obligated to give more than 10 minutes notice prior to curtailment. Absence of a designated representative or inability of the Company to communicate with the designated representative because of unanswered telephone, busy telephone, or otherwise, once

Company has initiated a telephonic communication to the designated representative, will in no way be regarded as an excuse for failure to comply with a curtailment request. The Company may request the customer to install at Customer's expense electronic equipment necessary for automatic notification of curtailment.

MONTHLY CHARGES AND CREDITS

Customer's net monthly bill for service provided under this Rider will be calculated in accordance with Company's applicable rate schedule, with the exception that a Curtailable Power Credit will be applied. The Curtailable Power Credit will be determined by applying a Demand Credit to the portion of the average kilowatt load used by the Customer during the 15 minute period of maximum use during the month in excess of the Firm kW. However, the Curtailable Power Credit will not exceed the product of the Demand Credit and the Curtailable kW.

The Demand Credit used to calculate the Monthly Curtailable Power Credit will be:

VOLTAGE LEVEL	DEMAND CREDIT
Secondary Service	$3.19/kW
Primary Service	$3.06/kW
Transmission Service	$2.91/kW

NON-COMPLIANCE PROVISIONS

Customer understands that service under this Rider is contingent upon Customer's complete and timely compliance with Company's requests for curtailment. If, at any time, Customer fails in whole or in part to implement or maintain any request for curtailment to reduce the Total kW to

the Firm kW, the Company may, at its option, elect to cancel, effective immediately, the Customer's eligibility for service under this Rider. Should the Company exercise this option, billing for the current and subsequent eleven (11) months will revert to the LP or LLP rate schedule, whichever is applicable. In addition, any Curtailable Power Credits received by the Customer during the 11 previous months shall be forfeited and reimbursed with interest to the Company over the six (6) month period following the cancellation of Customer's eligibility for service under this Rider.

LIMITATIONS ON CURTAILMENTS

Curtailments under this Rider are limited as follows:

Daily Limit: No longer than 12 hours in any day, measured from midnight to midnight, except during system emergencies as described below.

Annual Limit: No more than 400 hours in any calendar year.

The only curtailments included in curtailment time limits are those implemented at the request of Company for the purposes described in the "Conditions of Service" above. Extended interruptions resulting from failure of transmission or distribution equipment are not included in curtailment time limits. Curtailment time is measured from the time the Company notifies the Customer via telephonic communication when the period of curtailment will begin to the time that Company notifies Customer via telephonic communication that the period of curtailment will end.

During system emergencies when Company has made public pleas to restrict electric energy usage to essential needs because of an area or statewide shortage of electric power and/or energy, curtailable loads served under this Rider may be curtailed continuously without daily limit until such emergency condition has ended. Such curtailments shall be included in annual curtailment time limits.

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Curtailments of less than 15 minutes in duration shall constitute a 15-minute period for inclusion in Curtailable time limits.

Contract Minimum: The customer's minimum bill shall not be less than the applicable charge for the contracted demand minimum plus the applicable Fuel and Tax Adjustments and in no event shall the contract demand minimum be less than 500 kilowatts.

TERM OF CONTRACT

This Rider is being offered as an experimental service and may be withdrawn by the Company following written notice to each Customer served under the Rider given at least one year prior to such withdrawal. The obligation of the Customer shall continue for a minimum initial term of one year and continuing thereafter unless canceled by Customer following written notice given at least one year prior to such cancellation.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

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Original	**Sheet No:** R-37.1	Sheet 1 of 9
Replacing:	**Sheet No:**	
Name of Company: SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	**Class of Service:** As Applicable	
Part III. Rate Schedule No. 37		
Title: UNDERGROUND ELECTRIC DISTRIBUTION SERVICE AGREEMENT		

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I. SCOPE

This policy applies to installation of underground electric distribution systems where feasible from engineering, operation, and economic standpoint to serve. Underground Electric Distribution (UED) and similar phrases include not only electric facilities that are actually located underground, but also above ground which may be necessary to provide service to the customer.

Our basic philosophy, that the developer should pay the cost of underground electric distribution facilities that is in excess of the cost of overhead electric distribution facilities is to be maintained in all instances.

II. DEFINITION OF TERMS

A. For purposes of this policy the following abbreviations and definitions shall prevail:

1. Underground (US) Service -- Customer owned, maintained and installed underground service conductors, sometimes installed in a raceway, that extend from the Customer's meter to the point of delivery, where connection is made to Company's distribution system.

2. Overhead (OH) Service Drop -- Company owned and installed overhead service drop conductors that extend from the Company's overhead distribution

system to the point of delivery, where connection is made to Customer's electrical installation.

3. Point of Delivery -- The point of delivery of electric service shall be the point at which the electrical facilities of the Company connect to the electrical facilities of the Customer.

   a) For Overhead construction, the point of delivery is that point where the Company owned and installed OH Service Drop connects to the Customer owned service entrance wires which are located at the Customer's weatherhead. The Customer owned service entrance wires are connected by the customer to the source side of the meter socket and runs along the customer owned and installed service entrance raceway. The Service Entrance conductors extend out the weatherhead approximately 2 - 3 ft.

   b) For Underground construction, the point of delivery is that point where the Company owned distribution UED secondary facilities connect to the Customer owned and installed UED Service. The customer owned UED service is connected by the customer to the source side of the meter socket and runs underground from the Customer's meter location to the Company owned UED distribution facilities.

4. SWEPCO - Southwestern Electric Power Company.

5. Developer – A person, partnership, association, corporation, or governmental agency that owns, operates, or develops a subdivision or mobile home park.

6. Service Connections – The electrical facilities of the underground system installed, maintained and owned by developer extending from SWEPCO's secondary connection on the distribution system to the point of metering, but not including the meter(s). This would consist of the underground cable from customer's entrance equipment to SWEPCO's secondary pedestal or transformer.

7. Primary - That portion of the distribution system which delivers energy to the primary (high voltage) side of the distribution transformer from the substation or point of supply. Nominal voltages of these primary systems are 2.4 kV, 4Y/2.4 kV, 12.5Y/7.2 kV, and 34.5Y/19.9 kV.

8. Secondary - That portion of the distribution system which distributes the energy from the secondary (low voltage) side of the distribution transformer to the customers' service connection points at utilization voltage. Nominal voltages of these secondary systems are 120/240 volts, 240 volts, 208Y/120 volts, and 480Y/277 volts.

III. CONDITION OF SERVICE

A. UED will be made available in SWEPCO's service area where feasible from engineering, operation, and economic standpoint. The terms and conditions of the Company's Extension of Facilities Agreement (Schedule R-35.1) apply as

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Original **Sheet No:** R-37.4 Sheet 4 of 9

Replacing: **Sheet No:**

Name of Company: SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric **Class of Service:** As Applicable

Part III. Rate Schedule No. 37

Title: UNDERGROUND ELECTRIC DISTRIBUTION SERVICE AGREEMENT

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necessary. The cost estimate for all facilities provided, installed, owned, and maintained by the Company will include:

1. Material cost (purchased and stores);

2. Labor costs (Company and Contract);

3. Transportation cost;

4. Trenching (including backhoeing and boring);

    a) The customer may provide all trenching and backfilling to meet Company specifications.

    b) If the customer provides all trenching and backfilling to meet Company specifications, customer's (CIAC) will be reduced by that amount.

5. Right-of-way clearing, purchase, and acquisition;

6. Permanent Work Orders (PWO’s) (where applicable) and Overheads (exempt material);

7. Stores, Freight, and Handling;

8. Administrative & General costs; and

9. Engineering & Supervisory costs.

B. Differential cost: Customer will pay to Company prior to installation a contribution in aid to construction (CIAC) for all costs in excess of the cost of overhead electric distribution facilities. The CIAC will be grossed up for taxes.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

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Original	**Sheet No:** R-37.6	Sheet 6 of 9
Replacing:	**Sheet No:**	
Name of Company: SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	**Class of Service:** As Applicable	
Part III. Rate Schedule No. 37		
Title: UNDERGROUND ELECTRIC DISTRIBUTION SERVICE AGREEMENT		

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SOUTHWESTERN ELECTRIC POWER COMPANY

STANDARD AGREEMENT
FOR UNDERGROUND ELECTRIC DISTRIBUTION SYSTEM
BETWEEN

____

____

(Customer, Owner, Developer, Operator, or Builder)
Hereinafter referred to as Customer
AND
SOUTHWESTERN ELECTRIC POWER COMPANY

It is mutually understood and agreed that:

I. This Agreement applies to installation and operation of an underground electric distribution system on easement granted Southwestern Electric Power Company (SWEPCO) on ____ ____________________________________ and is further identified by SWEPCO Drawing No. _____ which is made a part of this Agreement.

II. Electric service covered by this Agreement shall be: (Indicate one)

( ) A. For individually metered customers in residential subdivisions, mobile home parks, apartment complexes, and apartments - single phase, 3 wire

at a nominal voltage of 120/240 volts.

( ) B. For primary metered apartment complexes - primary voltage and phases required are ______________________.

( ) C. For single point service for apartment projects metered at secondary voltage. (Indicate one)

( ) 1. Single phase, 3 wire at a nominal voltage of 120/240.
( ) 2. Three phase, 4 wire at a nominal voltage of 208Y/120.
( ) 3. Three phase, 4 wire at a nominal voltage of 480Y/277.
( ) 4. Three phase, 4 wire at a nominal voltage of 120/240.

III. Service entrance cables shall be installed underground between Customer's building and SWEPCO transformer or secondary service pedestal by Customer.

IV. SWEPCO reserves the right to designate the point of service for each lot, each apartment building, each mobile home space, and each commercial customer.

V. To insure reliability of service to all consumers in an apartment and commercial developments:

A. Customer will provide adequate overcurrent protection to each individual consumer.

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B. If Customer installs service feeders under a building to centrally located metering points, a spare conduit shall be provided by the Customer to permit rapid restoration of service.

VI. Customer will provide the utility an easement at final grade, the easement shall be clear of trees or other obstructions, as required, with all property corners staked before construction of residential underground electric distribution system begins.

VII. Location of underground facilities, other than the electric distribution system installed by or for the Customer shall be designated by the Customer prior to construction of the electric distribution system.

VIII. Any rearrangements in the electric distribution system or metering arrangement which may be required by the Customer after installation of distribution system shall be paid for by the Customer.

IX. SWEPCO will furnish and install the following equipment:

A. All primary and secondary cables. (Does not include service cable.)
B. Switch enclosures, transformers, transformer enclosures, secondary pedestals, and associated equipment.
C. Any overhead distribution required to provide this service.

X. The Customer will pay the Company the differential cost prior to the installation of (UED) facilities.

ARKANSAS PUBLIC SERVICE COMMISSION

Original **Sheet No:** R-37.9 Sheet 9 of 9

Replacing: **Sheet No:**

Name of Company: SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric **Class of Service:** As Applicable

Part III. Rate Schedule No. 37

Title: UNDERGROUND ELECTRIC DISTRIBUTION SERVICE AGREEMENT

PSC File Mark Only

XI. Customer will pay to the Company at the time of acceptance of the Agreement the sum of $__________ for temporary construction, removal or rearrangement of existing overhead facilities.

XII. Should Customer abandon the use of this underground electric distribution system, he agrees to pay to the Company an amount of money equal to the depreciated value of the system installed, plus the removal cost, less credit for salvage material or equipment.

ACCEPTED ________________________
DATE

WITNESS: ________________________________
Customer

________________________________ BY ________________________________

ACCEPTED ________________________
DATE

WITNESS: SOUTHWESTERN ELECTRIC POWER COMPANY

________________________________ BY ________________________________
SWEPCO Representative

ATTACHMENT: Drawing No. _________
Work Order No. __________
Rev. 072799

THIS SPACE FOR PSC USE ONLY

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-38.1 Sheet 1 of 1	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 38		
Title: RECREATIONAL LIGHTING		PSC File Mark Only

AVAILABILITY

This schedule is available for lighting of recreational fields and for miscellaneous recreational facilities to include restrooms and concession stands, where the Customer owns the lighting facilities and the electric service is metered. Non-lighting loads may not exceed 20% of the total lighting load.

Service under this schedule includes but is not limited to facilities with characteristics similar to athletic fields of schools, churches, and public recreational associations.

A written contract may be required at the option of the Company.

TYPE OF SERVICE

The electric service furnished will be to a single metered delivery point and will be at one standard voltage.

This rate schedule is not available for resale, stand-by, or supplemental service.

NET MONTHLY RATE

Customer Charge:	$10.60
Kilowatt-hour Charge:	$0.0373 per kilowatt hour

Adjustments:

Fuel Adjustment: In addition to all other charges, the amount of the Customer's bill will be adjusted by an amount per kilowatt-hour calculated according to the formula in the Energy Cost Recovery Rider - Arkansas.

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider - Arkansas.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under the Company's Standard Terms and Conditions.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-39.1 Sheet 1 of 3	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 39		
Title: ALTERNATE FEED SERVICE		PSC File Mark Only

AVAILABILITY

Alternate Feed Service (AFS) may be available for service to customers served under Lighting and Power and Large Lighting and Power Primary Service Schedules, who request an alternate feed service from existing distribution facilities which is in addition to the customer's basic service, provided that the Company can reasonably provide available capacity in existing distribution facilities adjacent to the customers requested delivery point.

NET MONTHLY RATE

In addition to all monthly charges for the customer's basic service as determined under the appropriate Schedule, the customer shall pay the following:

$5.06	Per kW of AFS billing demand for reserving AFS station and distribution line facilities at primary voltage.

AFS CAPACITY RESERVATION

The customer shall reserve a specific amount of AFS capacity equal to the customer's normal maximum requirements, but in no event shall the customer's AFS reserved capacity under this rider exceed the capacity reservation for the customer's basic service under the appropriate tariff. The Company shall not be required to supply AFS capacity in excess of that reserved except by mutual agreement.

Adjustments:

Tax Adjustment: In addition to all other charges, the amount of the Customer's bill will be increased by the proportionate part of any new tax or increased rate of tax in accordance with the Tax Adjustment Rider – Arkansas.

MEASUREMENT AND DETERMINATION OF DEMAND

The billing demand will be measured and billed in accordance with the tariff requirements set forth in the customer's basic service tariff.

EQUIPMENT AND INSTALLATION CHARGE

The Customer shall be required to pay a one-time equipment and installation charge for all facilities required to provide either a new or upgraded alternate feed service. The equipment and installation charge shall be determined by the Company and shall include, but not be limited to, (a) all cost of the alternate feed facilities, and (b) any cost of modifications to the customer's basic service necessary to install the alternate feed facilities. All equipment shall remain the property of the Company.

TERM

The customer shall contract for a definite amount of electrical capacity in kilowatts which shall be sufficient to meet normal maximum requirements under this Rider, but in no event shall the customer's contract capacity under this Rider exceed the contract capacity for the customer's basic service under the appropriate Schedule. The Company shall not be required to supply capacity in excess of that for which the customer has contracted.

Contracts will be required for an initial period of not less than one (1) year and shall remain in effect thereafter until either party shall give the other at least six (6) months' written notice of the intention to discontinue service under their Rider.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial periods longer than one (1) year pursuant to the Extension of Service provision of the Company's Terms and Conditions of Service.

SPECIAL TERMS AND CONDITIONS

The customer shall be responsible for supplying any switching apparatus and facilities which are required in order for the installation to conform to the Company's construction standards and requirements. In those cases where the Company supplies the switching apparatus to conform to the Company's standards and requirements, the customer shall be responsible for the total cost of the switching apparatus, installation, maintenance, and any future replacement costs.

Upon receipt of a request from the customer for non-standard AFS, the Company will provide the customer with a written estimate of all costs, including system impact study costs, and any applicable unique terms and conditions of service related to the provision of the non-standard AFS. The AFS agreement shall provide full disclosure of all rates, terms and conditions of service under this rider, and any and all agreements related thereto.

The Company will have sole responsibility for determining the basic service circuit and the AFS circuit.

Service under this Rider does not guarantee that power will be available through the alternate feed service at all times.

PAYMENT FOR SERVICE

Payment for Service Rider - See Rate Schedule 44.

TERMS AND CONDITIONS

Service will be furnished under Company's Standard Terms and Conditions.

TABLE OF CONTENTS

40. NET-METERING

40.1. AVAILABILITY

40.1.1. To any residential or any other customer who takes service under standard rate schedules Residential Service, Electric Heating Appliance Residential Service, General Service, Lighting and Power, Lighting and Power Time-of-Use, Large Lighting and Power, Municipal Service, Municipal Pumping (non-conjunction), and Recreational Lighting who is an owner of a Net-Metering Facility and has obtained a signed Standard Interconnection Agreement for Net-Metering Facilities with the Electric Utility. The generating capacity of Net-Metering Facilities may not exceed the greater of: 1) twenty-five kilowatts (25 kW) or 2) one hundred percent (100%) of the Net-Metering Customer's highest monthly usage in the previous twelve (12) months for Residential Use. The generating capacity of Net-Metering Facilities may not exceed three hundred kilowatts (300 kW) for non-residential use unless otherwise allowed by the Commission. Net-Metering is intended primarily to offset part or all of the customer's energy use.

The provisions of the customer's standard rate schedule are modified as specified herein.

40.1.2. Net-Metering Customers taking service under the provisions of this tariff may not simultaneously take service under the provisions of any other alternative source generation or co-generation tariff except as provided in the Net-Metering Rules.

40.2. MONTHLY BILLING

40.2.1. The Electric Utility shall separately meter, bill, and credit each Net-Metering Facility even if one (1) or more Net-Metering Facilities are under common ownership.

40.2.2. On a monthly basis, the Net-Metering Customer shall be billed the charges applicable under the currently effective standard rate schedule and any appropriate rider schedules. Under Net-Metering, only the kilowatt hour (kWh) units of a Net–Metering Customer's bill are netted.

40.2.3. If the kWhs supplied by the Electric Utility exceeds the kWhs generated by the Net-Metering Facility and fed back to the Electric Utility during the Billing Period, the Net-Metering Customer shall be billed for the net billable kWhs supplied by the Electric Utility in accordance with the rates and charges under the Net-Metering Customer's standard rate schedule.

40.2.4. If the kWhs generated by the Net-Metering Facility and fed back to the Electric Utility during the Billing Period exceed the kWhs supplied by the Electric Utility to the Net-Metering Customer during the applicable Billing Period, the Electric Utility shall credit the Net-Metering Customer with any accumulated Net Excess Generation in the next applicable Billing Period.

40.2.5. Net Excess Generation shall first be credited to the Net-Metering Customer's meter to which the Net-Metering Facility is physically attached (Generation Meter).

40.2.6. After application of 40.2.5 and upon request of the Net-Metering Customer pursuant to 40.2.8, any remaining Net Excess Generation shall be credited to one or more of the Net-Metering Customer's meters (Additional Meters) in the rank order provided by the Net-Metering Customer.

40.2.7. Net Excess Generation shall be credited as described in 40.2.5 and 40.2.6 during subsequent Billing Periods; the Net Excess Generation Credits remaining in a Net-Metering Customer's account at the close of a billing cycle shall not expire and shall be carried forward to subsequent billing cycles indefinitely. For Net Excess Generation Credits older than twenty-four (24) months, a Net-Metering Customer may elect to have the Electric Utility purchase the Net Excess Generation Credits in the Net-Metering Customer's account at the Electric Utility's estimated annual average cost rate for wholesale energy if the sum to be paid to the Net-Metering Customer is at least one hundred dollars ($100). An Electric Utility shall purchase at the Electric Utility's estimated annual average Avoided Cost rate for wholesale energy any Net Excess Generation Credits remaining in a Net-Metering Customer's account when the Net-Metering Customer: 1) ceases to be a customer of the Electric Utility; 2) ceases to operate the Net-Metering Facility; or transfers the Net-Metering Facility to another person.

When purchasing Net Excess Generation Credits from a Net-Metering Customer, the Electric Utility shall calculate the payment based on its annual average avoided energy costs in the applicable Regional Transmission Organization for the current year.

40.2.8. Upon request from a Net-Metering Customer the Electric Utility must apply Net Excess Generation to the Net-Metering Customer's Additional Meters provided that:

(a) The Net-Metering Customer must give at least 30 days' notice to the Electric Utility.

(b) The Additional Meter(s) must be identified at the time of the request. Additional Meter(s) shall be under common ownership within a single Electric Utility's service area; shall be used to measure the Net-Metering Customer's requirements for electricity; may be in a different class of service than the Generation Meter; shall be assigned to one, and only one, Generation Meter; shall not be a Generation Meter; and shall not be associated with unmetered service.

(c) In the event that more than one of the Net-Metering Customer's meters is identified, the Net-Metering Customer must designate the rank order for the Additional Meters to which excess kWhs are to be applied. The Net-Metering Customer cannot designate the rank order more than once during the Annual Billing Cycle.

40.2.9. Any Renewable Energy Credit created as the result of electricity supplied by a Net-Metering Customer is the property of the Net-Metering Customer that generated the Renewable Energy Credit.

PRELIMINARY INTERCONNECTION SITE REVIEW REQUEST

Southwestern Electric Power Company – State of Arkansas

I. STANDARD INFORMATION

Section 1. Customer Information

Name: ____

Contact Person: ____

Mailing Address:____

City:______________________ State: ________ Zip Code: __________

Facility Location (if different from above):____________________________

Daytime Phone: ______________ Evening Phone: ___________________

E-Mail Address: ____________________Fax: ______________________

If the requested point of interconnection is the same as an existing electric service, provide the electric service account number: ________________________________

Additional Customer Accounts (from electric bill) to be credited with Net Excess Generation: ____

Annual Energy Requirements (kWh) in the previous twelve (12) months for the account physically attached to the Net-Metering Facility and for any additional accounts listed (in the absence of historical data reasonable estimates for the class and character of service may be made):____

Section 2. Generation Facility Information

System Type: Solar Wind Hydro Geothermal Biomass Fuel Cell Micro Turbine (circle one)

Generator Rating (kW): ____________________ AC or DC (circle one)

Expected Capacity Factor: ____________________________________

Expected annual production of electrical energy (kWh) of the facility calculated using industry recognized simulation model (PVWatts, etc):___________________________

Section 3. Interconnection Information

Attach a detailed electrical diagram showing the configuration of all generating facility equipment, including protection and control schemes.

Requested Point of Interconnection: ____

Customer-Site Load (kW) at Net-Metering Facility location (if none, so state):

____

Interconnection Request: Single Phase: _______________ Three Phase: ________________

Section 4. Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Preliminary Interconnection Site Review is true and correct.

Signature: _____________________________________ Date: ______________________

II. TERMS AND CONDITIONS

Section 1. Requirements for Request

For the purpose of requesting that the Electric Utility conduct a preliminary interconnection site review for a proposed Net-Metering Facility pursuant to the requirement of Rule 2.05.B.4, or as otherwise requested by the customer, the customer shall notify the Electric Utility by submitting a completed Preliminary Interconnection Site Review Request. The customer shall submit a separate Preliminary Interconnection Site Review Request for each point of interconnection if information about multiple points of interconnection is requested. Part 1, Standard Information, Sections 1 through 4 of the Preliminary Interconnection Site Review Request must be completed for the notification to be valid. If mailed, the date of notification shall be the third day following the mailing of the Preliminary Interconnection Site Review Request. The Electric Utility shall provide a copy of the Preliminary Interconnection Site Review Request to the customer upon request.

<u>Section 2. Utility Review</u>

Following submission of the Preliminary Interconnection Site Review Request by the customer the Electric Utility shall review the plans of the facility interconnection and provide the results of its review to the customer, in writing, within 30 calendar days. If the customer requests that multiple interconnection site reviews be conducted the Electric Utility shall make reasonable efforts to provide the customer with the results of the review within 30 calendar days. If the Electric Utility cannot meet the deadline it will provide the customer with an estimated date by which it will complete the review. Any items that would prevent Parallel Operation due to violation of safety standards and/or power generation limits shall be explained along with a description of the modifications necessary to remedy the violations.

The preliminary interconnection site review is non-binding and need only include existing data and does not require the Electric Utility to conduct a study or other analysis of the proposed interconnection site in the event that data is not readily available. The Electric Utility shall notify the customer if additional site screening may be required prior to interconnection of the facility. The customer shall be responsible for the actual costs for conducting the preliminary interconnection site review and any subsequent costs associated with site screening that may be required.

<u>Section 3. Application to Exceed 300 kW Net-Metering Facility Size Limit</u>

This Preliminary Interconnection Site Review Request and the results of the Electric Utility's review of the facility interconnection shall be filed with the Commission with the customer's application to exceed the 300 kW facility size limit pursuant to Net Metering Rule 2.05.B.4.

<u>Section 4. Standard Interconnection Agreement</u>

The preliminary interconnection site review does not relieve the customer of the requirement to execute a Standard Interconnection Agreement prior to interconnection of the facility.

STANDARD INTERCONNECTION AGREEMENT FOR NET-METERING FACILITIES

Southwestern Electric Power Company – State of Arkansas

I. STANDARD INFORMATION

Section 1. Customer Information

Name: ____

Mailing Address: ______________________________________

City: ______________________ State: __________ Zip Code: ____________

Facility Location (if different from above): __________________________

Daytime Phone: ________________ Evening Phone: ________________

Utility Customer Account Number (from electric bill) to which the Net-Metering Facility is physically attached: ______________________________

Section 2. Generation Facility Information

System Type: Solar Wind Hydro Geothermal Biomass Fuel Cell Micro turbine (circle one)

Generator Rating (kW): ____________________ AC or DC (circle one)

Describe Location of Accessible and Lockable Disconnect (If required): ____

Inverter Manufacturer: ________________ Inverter Model: ____________

Inverter Location: ____________________ Inverter Power Rating: __________

Expected Capacity Factor: __________________________________

Expected annual production of electrical energy (kWh) calculated using industry recognized simulation model (PVWatts, etc.): ____________________

Section 3. Installation Information

Attach a detailed electrical diagram of the Net-Metering Facility.

Installed by: ____

Qualifications/Credentials: __________________________________

Mailing Address: ______________________________________

City: ______________________ State: __________ Zip Code: ____________

Daytime Phone: ________________ Installation Date: ________________

Section 4. Certification
The system has been installed in compliance with the local Building/Electrical Code of ____(City/County)
Signed (Inspector):________________________ Date:____________________
(In lieu of signature of inspector, a copy of the final inspection certificate may be attached.)

The system has been installed to my satisfaction and I have been given system warranty information and an operation manual, and have been instructed in the operation of the system.
Signed (Owner):______________________________ Date:______________

Section 5. E-mail Addresses for parties
Customer's e-mail address: ____
Utility's e-mail address: ________________________ (To be provided by utility.)

Section 6. Utility Verification and Approval
Facility Interconnection Approved: _______________________ Date: _________
Metering Facility Verification by: _______________ Verification Date: __________

II. INTERCONNECTION AGREEMENT TERMS AND CONDITIONS

This Interconnection Agreement for Net-Metering Facilities ("Agreement") is made and entered into this ________day of _________, 20_______, by _________________________ _________("Electric Utility") and __________________________ ("Customer"), a____________(specify whether corporation or other), each hereinafter sometimes referred to individually as "Party" or collectively as the "Parties". In consideration of the mutual covenants set forth herein, the Parties agree as follows:

Section 1. The Net-Metering Facility
The Net-Metering Facility meets the requirements of Ark. Code Ann. § 23-18-603(6) and the Arkansas Public Service Commission's *Net-Metering Rules*.

Section 2. Governing Provisions
The Parties shall be subject to the provisions of Ark. Code Ann. § 23-18-604 and the terms and conditions set forth in this Agreement, the Commission's *Net-Metering Rules*, the Commission's *General Service Rules*, and the Electric Utility's applicable tariffs.

Section 3. Interruption or Reduction of Deliveries

The Electric Utility shall not be obligated to accept and may require Customer to interrupt or reduce deliveries when necessary in order to construct, install, repair, replace, remove, investigate, or inspect any of its equipment or part of its system; or if it reasonably determines that curtailment, interruption, or reduction is necessary because of emergencies, forced outages, force majeure, or compliance with prudent electrical practices. Whenever possible, the Utility shall give the Customer reasonable notice of the possibility that interruption or reduction of deliveries may be required. Notwithstanding any other provision of this Agreement, if at any time the Utility reasonably determines that either the facility may endanger the Electric Utility's personnel or other persons or property, or the continued operation of the Customer's facility may endanger the integrity or safety of the Utility's electric system, the Electric Utility shall have the right to disconnect and lock out the Customer's facility from the Electric Utility's electric system. The Customer's facility shall remain disconnected until such time as the Electric Utility is reasonably satisfied that the conditions referenced in this Section have been corrected.

Section 4. Interconnection

Customer shall deliver the as-available energy to the Electric Utility at the Electric Utility's meter.

Electric Utility shall furnish and install a standard kilowatt hour meter. Customer shall provide and install a meter socket for the Electric Utility's meter and any related interconnection equipment per the Electric Utility's technical requirements, including safety and performance standards.

The customer shall submit a Standard Interconnection Agreement to the Electric Utility at least thirty (30) days prior to the date the customer intends to interconnect the Net-Metering Facilities to the utility's facilities. Part I, Standard Information, Sections 1 through 4 of the Standard Interconnection Agreement must be completed to be valid. The customer shall have all equipment necessary to complete the interconnection prior to such notification. If mailed, the date of notification shall be the third day following the mailing of the Standard Interconnection Agreement. The Electric Utility shall provide a copy of the Standard Interconnection Agreement to the customer upon request.

ARKANSAS PUBLIC SERVICE COMMISSION

Following submission of the Standard Interconnection Agreement by the customer, the utility shall review the plans of the facility and provide the results of its review to the customer, in writing, within 30 calendar days. Any items that would prevent Parallel Operation due to violation of applicable safety standards and/or power generation limits shall be explained along with a description of the modifications necessary to remedy the violations.

If the Electric Utility's existing facilities are not adequate to interconnect with the Net-Metering Facility, the Customer shall pay the cost of additional or reconfigured facilities prior to the installation or reconfiguration of the facilities.

To prevent a Net-Metering Customer from back-feeding a de-energized line, the customer shall install a manual disconnect switch with lockout capability that is accessible to utility personnel at all hours. This requirement for a manual disconnect switch will be waived if the following three conditions are met: 1) The inverter equipment must be designed to shut down or disconnect and cannot be manually overridden by the customer upon loss of utility service; 2) The inverter must be warranted by the manufacturer to shut down or disconnect upon loss of utility service; and 3) The inverter must be properly installed and operated, and inspected and/or tested by utility personnel.

Customer, at his own expense, shall meet all safety and performance standards established by local and national electrical codes including the National Electrical Code (NEC), the Institute of Electrical and Electronics Engineers (IEEE), the National Electrical Safety Code (NESC), and Underwriters Laboratories (UL).

Customer, at his own expense, shall meet all safety and performance standards adopted by the utility and filed with and approved by the Commission that are necessary to assure safe and reliable operation of the Net Metering Facility to the utility's system.

Customer shall not commence Parallel Operation of the Net-Metering Facility until the Net Metering Facility has been inspected and approved by the Electric Utility. Such approval shall not be unreasonably withheld or delayed. Notwithstanding the foregoing, the Electric Utility's approval to operate the Customer's Net-Metering Facility in parallel with the Utility's electrical system should not be construed as an endorsement, confirmation, warranty, guarantee, or representation concerning the safety, operating characteristics, durability, or reliability of the Customer's Net-Metering Facility.

Section 5. Modifications or Changes to the Net-Metering Facility Described in Part 1, Section 2

Prior to being made, the Customer shall notify the Electric Utility of, and the Electric Utility shall evaluate, any modifications or changes to the Net-Metering Facility described in Part 1, Standard Information, Section 2 of the Standard Interconnection Agreement for Net-Metering Facilities. The notice provided by the Customer shall provide detailed information describing the modifications or changes to the Utility in writing, including a revised Standard Interconnection Agreement for Net-Metering Facilities that clearly identifies the changes to be made. The Electric Utility shall review the proposed changes to the facility and provide the results of its evaluation to the Customer, in writing, within thirty (30) calendar days of receipt of the Customer's proposal. Any items that would prevent Parallel Operation due to violation of applicable safety standards and/or power generation limits shall be explained along with a description of the modifications necessary to remedy the violations.

If the Customer makes such modification without the Electric Utility's prior written authorization and the execution of a new Standard Interconnection Agreement, the Electric Utility shall have the right to suspend Net-Metering service pursuant to the procedures in Section 6 of the Commission's General Service Rules.

A Net-Metering Facility shall not be modified or changed to generate electrical energy in excess of the amount necessary to offset all of the Net-Metering Customer requirements for electricity.

Section 6. Maintenance and Permits

The customer shall obtain any governmental authorizations and permits required for the construction and operation of the Net-Metering Facility and interconnection facilities. The Customer shall maintain the Net-Metering Facility and interconnection facilities in a safe and reliable manner and in conformance with all applicable laws and regulations.

Section 7. Access to Premises

The Electric Utility may enter the Customer's premises to inspect the Customer's protective devices and read or test the meter. The Electric Utility may disconnect the interconnection facilities without notice if the Electric Utility reasonably believes a hazardous condition exists and such immediate action is necessary to protect persons, or the Electric Utility's facilities, or property of others from damage or interference caused by the Customer's facilities, or lack of properly operating protective devices.

Section 8. Indemnity and Liability

The following is Applicable to Agreements between the Electric Utility and to all Customers except the State of Arkansas and any entities thereof, local governments and federal agencies:

Each Party shall indemnify the other Party, its directors, officers, agents, and employees against all loss, damages, expense and liability to third persons for injury to or death of persons or injury to property caused by the indemnifying party's engineering, design, construction, ownership, maintenance or operations of, or the making of replacements, additions or betterment to, or by failure of, any of such Party's works or facilities used in connection with this Agreement by reason of omission or negligence, whether active or passive. The indemnifying Party shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity. The indemnifying Party shall pay all costs that may be incurred by the other Party in enforcing this indemnity. It is the intent of the Parties hereto that, where negligence is determined to be contributory, principles of comparative negligence will be followed and each Party shall bear the proportionate cost of any loss, damage, expense and liability attributable to that Party's negligence. Nothing in this paragraph shall be applicable to the Parties in any agreement entered into with the State of Arkansas or any entities thereof, or with local governmental entities or federal agencies. Furthermore, nothing in this Agreement shall be construed to waive the sovereign immunity of the State of Arkansas or any entities thereof. The Arkansas State Claims Commission has exclusive jurisdiction over claims against the state.

Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to or any liability to any person not a Party to this Agreement. Neither the Electric Utility, its officers, agents or employees shall be liable for any claims, demands, costs, losses, causes of action, or any other liability of any nature or kind, arising out of the engineering, design, construction, ownership, maintenance or operation of, or the making of replacements, additions or betterment to, or by failure of, the Customer's facilities by the Customer or any other person or entity.

Section 9. Notices
The Net-Metering Customer shall notify the Electric Utility of any changes in the information provided herein.

All written notices shall be directed as follows:

Southwestern Electric Power Company
Attention: Customer Services Manager
P. O. Box 21106
Shreveport, LA 71156

Attention:
[Customer]
Name: ____________________________________
Address: __________________________________
City:_____________________________________

Customer notices to Electric Utility shall refer to the Customer's electric service account number set forth in Section 1 of this Agreement.

Section 10. Term of Agreement
The term of this Agreement shall be the same as the term of the otherwise applicable standard rate schedule. This Agreement shall remain in effect until modified or terminated in accordance with its terms or applicable regulations or laws.

Section 11. Assignment
This Agreement and all provisions hereof shall inure to and be binding upon the respective Parties hereto, their personal representatives, heirs, successors, and assigns. The Customer shall not assign this Agreement or any part hereof without the prior written consent of the Electric Utility, and such unauthorized assignment may result in termination of this Agreement.

<u>Section 12. Net-Metering Customer Certification</u>

I hereby certify that all of the information provided in this Agreement is true and correct, to the best of my knowledge, and that I have read and understand the Terms and Conditions of this Agreement.

Signature: ______________________________ Date: ____________________

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized representatives.

Dated this ____________________ day of _________________, 20__.

Customer:	Electric Utility:
______________________________	______________________________
By: ______________________________	By: ______________________________
Title: ______________________________	Title: ______________________________
Mailing Address: ______________________________ ______________________________ ______________________________	Mailing Address: Southwestern Electric Power Company P. O. Box 21106 Shreveport, LA 71156
E-mail Address: ______________________________	E-mail Address: ______________________________

STANDARD INTERCONNECTION AGREEMENT FOR NET-METERING FACILITIES

Southwestern Electric Power Company – State of Arkansas

Disclaimer

POSSIBLE FUTURE RULES OR RATE CHANGES, OR BOTH AFFECTING YOUR NET-METERING FACILITY

The following is a supplement to the Interconnection Agreement you signed with Southwestern Electric Power Company.

1. Electricity rates, basic charges, and service fees, set by Southwestern Electric Power Company and approved by the Arkansas Public Service Commission (Commission), are subject to change.

2. I understand that I will be responsible for paying any future increases to my electricity rates, basic charges, or service fees from Southwestern Electric Power Company.

3. My Net-Metering System is subject to the current rates of Southwestern Electric Power Company, and the rules and regulations of the Commission. Southwestern Electric Power Company may change its rates in the future with approval of the Commission or the Commission may alter its rules and regulations, or both may happen. If either or both occurs, my system will be subject to those changes.

By signing below, you acknowledge that you have read and understand the above disclaimer.

____
Name (printed)

____
Signature

____
Date

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-41.1 Sheet 1 of 1	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 41		
Title: RESERVED FOR FUTURE USE		PSC File Mark Only

Reserved for Future Use

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-42.1 Sheet 1 of 1	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 42		
Title: Radio Frequency Meter Installation Rider		PSC File Mark Only

AVAILABILITY

The Rider for Radio Frequency Meter Installation is available upon request to customers who are served under a rate schedule that requires no more than a single-phase, kWh only meter. A customer may request or elect upon request by the Company to have a radio frequency meter installed under the terms of this Rider as a mutually agreeable solution to Company personnel's lack of meter reading access to Company metering equipment on a customer's premises, due to a locked gate, animal concern, safety concern or other reason.

CONDITION OF SERVICE

The Company will install, own, operate, and maintain the radio frequency meters installed under this Rider. All radio frequency meters installed under this Rider shall remain the property of the Company. After a radio frequency meter is installed, the customer is responsible for keeping the line-of-site clear from obstructions that may impede the reading of the radio frequency meter. The radio frequency meter is not transferable to another location within the Company's service territory to which the customer may move.

Some locations may not be suitable for installation of a radio frequency meter due to possible interference or limitations of the transmitting device. If it is determined by the Company that a location is not suitable for the installation, the radio frequency meter will not be installed and the Company will refund any prior payment received under this Rider.

INSTALLATION FEE

The Radio Frequency Meter Installation Fee is a one-time, non-refundable fee based on the charges as set out below:

For premises requiring a meter exchange	$100.00 per meter
Each additional meter at the same premises	$ 70.00 per meter
For premises requiring new meter installation	$ 53.00 per meter

PAYMENT

The Company will invoice the requesting customer for the total installation fee and will install the radio frequency meter after receipt of payment. The fee is non-refundable after the radio frequency meter is installed.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	**Sheet No:** R-43.1	Sheet 1 of 1
Replacing:	**Sheet No:**	
Name of Company: SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	**Class of Service:** As Applicable	
Part III. Rate Schedule No. 43		
Title: RESERVED FOR FUTURE USE		

PSC File Mark Only

Reserved for future use

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-44.1 Sheet 1 of 1	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 44		
Title: PAYMENT FOR SERVICE RIDER (Rules of Practice and Procedure 11.04(b)(10)(B)		PSC File Mark Only

PAYMENT FOR SERVICE

Customers who pay within 22 days of the date of the bill will pay the net bill computed on the Net Monthly Rate. The gross bill will be payable after 22 days of the date of the bill. The gross bill will be the total net bill plus the sum of 10 percent of the first $30 of the net bill plus 2 percent of the amount over $30.

This rider is applicable to the following rate schedules:

2, 3, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 25, 26, 27, 28, 29, 30, 31, 32, 34, 35, 36, 37, 38, 39.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-45.1	Sheet 1 of 5 Including Attachment	
Replacing:	Sheet No.		
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY			
Kind of Service: Electric	Class of Service: All		
Part III. Rate Schedule No. 45			
Title: ENERGY EFFICIENCY COST RECOVERY RIDER (Rider EECR)			PSC File Mark Only

PURPOSE

The purpose of the Energy Efficiency Cost Recovery Rider ("Rider EECR") is to establish the EECR Rate(s) by which Southwestern Electric Power Company (Company) will recover its energy efficiency program costs approved by the Commission in Docket No. 07-082-TF; including, but not limited to: (1) incremental energy efficiency program costs ("Incremental Program Costs"); (2) lost contributions to fixed costs ("LCFC") as described and approved by the Commission in Order No. 14 issued in Docket No 08-137-U; (3) utility incentive as described and approved by the Commission in Order No 15 issued in Docket No. 08-137-U; and (4) a "true-up" adjustment (collectively, the "Recoverable Costs"). Recovery of Incremental Program Costs is limited to the incremental costs which represent the direct program costs that are not already included in the then current rates of the Company. The EECR Rate(s) will be calculated to recover the Company's Recoverable Costs over the period in which the EECR Rate(s) will be in effect.

ANNUAL REDETERMINATION

On or before May 1 of each year, redetermined EECR Rate(s) shall be filed by the Company with the Commission in accordance with the provisions of Section 7 of the Commission's *Rules for Conservation and Energy Efficiency Programs*. The redetermined EECR Rate(s) shall be determined by application of the EECR Rate Formula set out in Attachment A to this Rider EECR. Each such revised EECR Rate shall be filed in Docket No. 07-082-TF and shall be accompanied by supporting testimony and a set of workpapers sufficient to fully document the calculations of the revised EECR Rates(s).

The redetermined EECR Rate(s) shall reflect projected Recoverable Costs for the next calendar year (the "Recoverable Year"); including, but not limited to: (1) the approved incremental Program Costs for the Recoverable Year; (2) the projected LCFC for the Recoverable Year, which shall be inclusive of LCFC for prior reporting years that are not already included within the Company's most recently established base rates; (3) the incentive earned in the prior calendar year (the "Reporting Year"), if any; and (4) a

true-up adjustment reflecting the over-recovery or under-recovery of the EECR Recoverable Costs for the Reporting Year. The true-up adjustment will be calculated to include the effect of carrying costs using the Company's most recently approved rate of return on rate base. The EECR Rate(s) so redetermined shall be effective for bills rendered on and after the first billing cycle of January of the Recoverable Year and shall then remain in effect for twelve (12) months ("EECR Cycle"), except as otherwise provided for below.

INTERIM ADJUSTMENT

Should a cumulative over-recovery or under-recovery balance arise during any EECR Cycle which exceeds ten (10) percent of the EECR Recoverable Costs determined for the EECR Cycle included in the most recently filed rate redetermination under this Rider EECR, then either the Commission General Staff or the Company may propose an interim revision to the then currently effective EECR Rate(s).

TRACKING AND MONITORING PROGRAM COSTS AND BENEFITS

The Company shall develop and implement appropriate accounting procedures, subject to the review of the Commission General Staff, which provide for separate tracking, accounting, and reporting of all program costs incurred by the Company. The procedures shall enable energy efficiency program costs to be readily identified and clearly separated from all other costs. The Company shall secure and retain all documents necessary to verify the validity of the program costs for which it is seeking recovery. Such documents shall include, but not be limited to, vouchers, journal entries, and the date the participant's project was completed.

The Company shall develop and implement appropriate accounting procedures, subject to the review of the Commission General Staff, which provide for separate tracking, accounting, and reporting of

revenues collected through the Rider EECR. The procedures shall enable the EECR revenues to be readily identified and clearly separated from all other revenues. The Company shall secure and retain all documents necessary to verify the accuracy of the EECR revenues. Such documents shall include, but not be limited to, billing determinants, journal entries, and summary revenue reports.

For the purpose of assessing the benefits and effectiveness of the programs, the Company shall develop and implement appropriate procedures, subject to the review of the Commission General Staff, which provide for separate tracking of the benefits and the effectiveness of the programs. The data that shall be tracked shall include, but shall not be limited to, information that will enable the Commission to assess the effectiveness of the programs. The Company shall secure and retain all documents necessary to verify its assessments.

TRACKING AND MONITORING LCFC AND INCENTIVE

The Company shall track and monitor LCFC and Incentives in accordance with Order Nos. 14 and 15, respectively, issued in Docket No. 08-137-U and in future Orders addressing LCFC and Incentives.

TERM

This Rider EECR shall remain in effect until modified or terminated in accordance with the provisions of the Rider EECR or applicable regulations or laws.

If this Rider EECR is terminated by a future order of the Commission, the EECR Rate(s) then in effect shall continue to be applied until the Commission approves an alternative mechanism by which the Company can recover its energy efficiency costs. At that time, any cumulative over-recovery or under-recovery resulting from application of the just terminated EECR Rate(s) shall be applied to customer billings over the twelve (12) month billing period beginning on the first billing cycle of the second month following the termination of Rider EECR in a manner prescribed by the Commission.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-45.4	Sheet 4 of 5 Including Attachment	
Replacing:	Sheet No.		
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY			
Kind of Service: Electric	Class of Service: All		
Part III. Rate Schedule No. 45			
Title: ENERGY EFFICIENCY COST RECOVERY RIDER (Rider EECR)			PSC File Mark Only

APPLICABLE RATE SCHEDULES

Residential Class:
Residential,
Residential, Electric Heating Appliance Residential Service,
Commercial/Industrial Class:
General Service,
Lighting & Power Service – Secondary,
Lighting & Power Service – Primary,
Lighting & Power TOU – Primary,
Lighting & Power TOU – Secondary;
Large Lighting & Power – Primary,
Large Lighting & Power – Transmission,
Pulp and Paper Mill – Transmission,
Supplemental, Backup, Maintenance, and As-Available Standby Power Service,
Recreational Lighting
Municipal Class:
Municipal Pumping Service,
Municipal Service;
Lighting Class:
Municipal Street & Parkway Lighting,
Public Street & Highway Lighting,
Private Lighting,
Area Lighting.

The appropriate EECR rate will be applicable to any new rate schedule approved by the Commission.

Southwestern Electric Power Company
Energy Efficiency Cost Recovery Rider (Rider EECR)
ATTACHMENT A

	Total Recoverable Costs	Residential	Commercial/ Small Industrial	Industrial	Municipal	Lighting
2006-2007 Ark. Energy Efficiency Expenses	18,600					
Education Iniatitive	82,000					
Ark. Weatherization Program	188,800					
Energy Star Appliance Program	100,500					
Compact Fluorescent Lighting	89,000					
Commercial/Industrial Standard Offer	287,400					
Emergency Load Management (loadshare)	180,300					
1 **Total of All Programs**	$ 946,600					
2 Allocator (1)	100.0%	27.9840%	52.1359%	18.4416%	0.5591%	0.8794%
3 Allocated Current Recoverable	$ 946,600	$ 264,896	$ 493,519	$ 174,568	$ 5,292	$ 8,325
4 Prior Period Over/Under, includes carrying costs	$ -	$ -	$ -	$ -	$ -	$ -
5 Total Recoverable Amount	$ 946,600	$ 264,896	$ 493,519	$ 174,568	$ 5,292	$ 8,325
6 Billing Units - kWh (Nov 07-Dec 08)	5,137,316,385	1,337,668,450	2,793,727,850	936,300,640	22,124,184	47,495,261
7 EECR Rate ($/kWh)	$ 0.00018	$ 0.00020	$ 0.00018	$ 0.00019	$ 0.00024	$ 0.00018

(1) Demand and Energy Allocator from Cost Of Service study (June 1998)

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-46.1 Sheet 1 of 5	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 46		
Title: FEDERAL LITIGATION CONSULTING FEE RIDER		PSC File Mark Only

1. PURPOSE

The Federal Litigation Consulting Fee Rider defines the procedures by which the Federal Litigation Consulting Fee Rate shall be determined. The Federal Litigation Consulting Fee Rate shall recover the fees and expenses paid by Southwestern Electric Power Company ("Company") to contract attorneys and consultants retained by the Arkansas Public Service Commission (Commission), as authorized by the General Assembly, when it participates in litigation before a federal agency or federal court in proceedings which affect the Company. See Ark. Code Ann. §23-4-102.

2. APPLICATION

The Federal Litigation Consulting Fee Rate is applicable to all electric service billed under the rate schedules designated in Attachment A to this Rider. The Net Monthly Rates of the Company's currently effective rate schedules will be adjusted by the Federal Litigation Consulting Fee Rate amount set forth in Attachment A to this Rider, which shall apply during the period indicated thereon. The Federal Litigation Consulting Fee Rate amounts shall be revised pursuant to the procedures described in Section 6 below.

3. BILL REVIEW AND PAYMENT

When involved in federal litigation, bills for litigation consulting fees and expenses shall be submitted by the contracting attorney(s) and/or consultant(s) to the Commission on a monthly basis. After review and approval by the Commission, the Commission will forward the bills for the approved fees and expenses to the Company Designees listed in Section 4 below. The maximum amount that may be directly recovered shall not exceed $3,000,000 annually.

The Company shall remit payment for the Federal Litigation Consulting Fees directly to the contracting party within thirty (30) days of the bill's receipt by the Company. A record of the payments will be maintained in an appropriate, separate account.

4. COMPANY DESIGNEES

Lynn Ferry-Nelson
Director Regulatory Services
SWEPCO
P.O. Box 21106
Shreveport, La 71156

Elizabeth Stephens
Regulatory Consultant
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P.O. Box 21106
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5. ANNUAL RATE REVISIONS

5.1 Annual Filing Requirements
On or before February 15 of any year following a calendar year in which Federal Litigation Consulting Fees are paid, the Company may file for recovery of the Federal Litigation Consulting Fees. The Federal Litigation Consulting Fees Rate shall be calculated annually in accordance with the provisions of Paragraph 6.1 and filed for approval with the Commission.

Once a docket is established, annual revisions shall be filed in the same docket each year thereafter. Each Federal Litigation Consulting Fee rate filing shall be accompanied by a set of workpapers sufficient to fully document the timely payment of the third party contract fees and expenses, the accounting treatment for such payments, and the calculation of the rate.

6. CALCULATION AND RECOVERY PROCEDURES

6.1 Federal Litigation Consulting Fee Rate Calculation

The Federal Litigation Consulting Fee rate shall include the Commission-approved contract fees and expenses paid in the preceding calendar year. The rate shall not include any interest or carrying charges. The Federal Litigation Consulting Fee rate shall be determined by dividing the federal litigation consulting fees and expenses paid by the projected energy sales for the twelve-month period commencing on April 1 of each year. This rate shall also include a true-up adjustment reflecting the over-recovery or under-recovery of the federal litigation consulting fees for the preceding calendar year.

The Federal Litigation Consulting Fee rate so determined shall be effective, after Commission approval, for bills rendered on and after the first billing cycle of April of the filing year and shall then remain in effect until the last billing cycle of March of the following year, or other billing period as approved by the Commission.

Should there be unusual circumstances either the Company or the Staff may propose to modify the above calculation.

6.2 <u>Federal Litigation Consulting Fee Rate Recovery</u>
The Federal Litigation Consulting Fee rate, once approved by the Commission, shall be applied to each customer's monthly billing energy (kWh). The rate shall be constant across all customer classes and applied to the currently effective rate schedules. The Federal Litigation Consulting Fee Rate shall be set forth in Attachment A to this Rider and shall be filed with the utilities' tariffs.

6.3 <u>Federal Litigation Consulting Fee Rate True-up</u>
At the time of the annual filing, the actual recovery of Federal Litigation Consulting Fees will be compared to the projected recovery for the preceding calendar year. Any net over-recovery or under-recovery of the Federal Litigation Consulting Fees shall be included in setting the Federal Litigation Consulting Fee rate for the next recovery period.

Southwestern Electric Power Company
Federal Litigation Consulting Fee Rate
ATTACHMENT A

The Net Monthly rates for all customers shall be adjusted by the following amount for recovery of the Federal Litigation Consulting Fee from the first billing cycle of (month) 20XX through the last billing cycle of (month) 20XX.

$x.xxxxxx per kWh

Applicable Rate Schedules

Residential Service,
Residential, Electric Heating Appliance Residential Service,
General Service,
Lighting & Power Service – Secondary,
Lighting & Power Service – Primary,
Lighting & Power TOU – Primary,
Lighting & Power TOU – Secondary;
Large Lighting & Power – Primary,
Large Lighting & Power – Transmission,
Pulp and Paper Mill – Transmission
Supplemental, Backup, Maintenance, and As-Available Standby Power Service
Municipal Pumping Service,
Municipal Service;
Municipal Street & Parkway Lighting,
Public Street & Highway Lighting,
Private Lighting,
Area Lighting,
Recreational Lighting.

The Federal Litigation Consulting Fee Rider shall apply to all kilowatt-hours billed during each monthly billing cycle. For electric service billed under applicable rate schedules for which there is no metering, the Company shall estimate the monthly kWh usage and the Federal Litigation Consulting Fee Rider shall be applied.

THIS SPACE FOR PSC USE ONLY

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-47.1 Sheet 1 of 1	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 47		
Title: RESERVED FOR FUTURE USE		PSC File Mark Only

This Schedule has been removed from the tariff book.

Reserved for Future Use

THIS SPACE FOR PSC USE ONLY

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-48.1 Sheet 1 of 1	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 48		
Title: RESERVED FOR FUTURE USE		PSC File Mark Only

This Schedule has been removed from the tariff book.

Reserved for Future Use

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-49.1 Sheet 1 of 1	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. 49		
Title: RESERVED FOR FUTURE USE		PSC File Mark Only

This Schedule has been removed from the tariff book.

Reserved for Future Use

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-50.1	Sheet 1 of 23 Including Attachments	
Replacing:	Sheet No.		
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY			
Kind of Service: Electric	Class of Service: All		
Part III. Rate Schedule No. 50			
Title: FORMULA RATE REVIEW (FRR) RIDER			PSC File Mark Only

REGULATORY AUTHORITY

The Arkansas General Assembly has delegated authority to the Arkansas Public Service Commission ("APSC" or the "Commission") to regulate public utilities in the State of Arkansas, including Southwestern Electric Power Company ("SWEPCO" or the "Company"). The Arkansas General Assembly has enacted the Formula Rate Review Act, Ark. Code Ann. §§ 23-4-1201 *et seq.*, which authorizes use of this Formula Rate Review ("FRR") Rider.

PURPOSE

The FRR defines the procedure by which all rates and applicable riders (Rate Schedules) on file with the APSC, except those excluded in Attachment A.1 to this FRR, may be periodically adjusted. The FRR shall apply to all electric service billed under the Rate Schedules, whether metered or unmetered.

DEFINITIONS

EFFECTIVE DATE -

Rates pursuant to the initial FRR shall become effective with the first billing cycle of October 2021 and subsequently adjusted FRR rates shall be effective with the first billing cycle of each successive projected year.

FORMULA RATE REVIEW TEST PERIOD -

The Formula Rate Review Test Period shall be a test period based upon a Historical Year. A Historical Year shall be the twelve (12) month period ending December 31 of the year preceding the filing of an Evaluation Report.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-50.2	Sheet 2 of 23 Including Attachments	
Replacing:	Sheet No.		
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY			
Kind of Service: Electric	Class of Service: All		
Part III. Rate Schedule No. 50			
Title: FORMULA RATE REVIEW (FRR) RIDER			PSC File Mark Only

ANNUAL FILING AND REVIEW

ANNUAL FILING

On or about April 1, 2021 and on or about April 1 of each subsequent year during the term of the FRR, SWEPCO shall file a report ("Evaluation Report") with the Commission containing an evaluation of the Company's earnings pursuant to the FRR for the Historical Year. Attachment A-1 shall be included in each such filing and shall contain the Company's proposed Rate Adjustment. The Evaluation Report and the Rate Adjustment shall be filed pursuant to the FRR.

REVIEW PERIOD

The Parties shall file a statement of error(s) or objection(s) and supporting Testimony with or without Exhibits at least 90 days before the date on which the Rate Adjustment becomes effective. The Company shall have fifteen (15) days to review the statement of error(s) or objection(s), to work with the Parties to resolve any differences, and to address the error(s) and objection(s) raised by the Parties by filing either a corrected Attachment A.1 or Rebuttal Testimony with or without Exhibits.

HEARING AND APPROVAL OF RATE ADJUSTMENT

Following a hearing at least fifty (50) days before the date on which the Rate Adjustment shall become effective, unless waived by SWEPCO and the Parties, the Commission shall issue a final order in which it resolves any issues in dispute and approves the Rate Adjustment at least twenty (20) days before the date on which the Rate Adjustment shall become effective. If a final order is not issued by such date, the initially filed or revised Rate Adjustment shall become effective for bills rendered on and after the first billing cycle of October, subject to refund, and shall remain in effect until changed by final order of the Commission or by operation of other provisions of this FRR.

If the Commission's final ruling on any disputed issues requires changes to the Rate Adjustment, the Company shall file a revised Attachment A-1 containing such further modified Rate Adjustment within five (5) days after receiving the Commission's order resolving the disputed issues. The Parties shall have three (3) days to review the revised Attachment A-1. The revised Attachment A-1 shall be implemented as ordered by the Commission.

FRR BANDWIDTH CALCULATION

The Total FRR revenue level shall be adjusted in the FRR review mechanism based on a comparison of the ERR to the TRR calculated using the following formula:

A. If the ERR is less than the TRR minus five-tenths percent (0.50%), the Total FRR Revenue level shall be increased by the amount necessary to increase the ERR to the TRR.

B. If the ERR is greater than the TRR plus five-tenths percent (0.50%), the Total FRR Revenue level shall be decreased by the amount necessary to decrease the ERR to the TRR.

C. There shall be no change to the FRR Revenue level if the ERR is less than or equal to the TRR plus five-tenths percent (0.50%), and greater than or equal to the TRR minus five-tenths percent (0.50%).

FRR REVENUE ALLOCATION

The total change in the formula rate revenue level shall be allocated to each applicable rate class based on an equal percentage of the base rate revenue used in the development of rates approved by the Commission in Docket No. 19-008-U. The total amount of such revenue increase or decrease for each rate class shall not exceed four percent (4%) of the revenue for each rate class for the Filing Year.

TERM

The initial term of the FRR rider shall not exceed five (5) years from the date of the Commission's final order in Docket No. 19-008-U. If SWEPCO requests an extension of the FRR rider, SWEPCO shall make such request in accordance with the Extension of Term provisions of the Formula Rate Protocols.

If the FRR is not extended, the then-existing Total FRR rates shall continue to be in effect until new base rates are duly approved and implemented.

ANNUAL DETERMINATION OF RATE ADJUSTMENT
INDEX OF ATTACHMENTS

Attachment	Description
A-1	FRR Rate Adjustment (Rate Adjustment).
A-2	FRR Revenue Change and includes the calculation of the total FRR Revenue to be collected in the Projected Year.
B-1	Earned Rate of Return ("ERR") on Common Equity. The ERR is the Company's return on common equity calculated by dividing the weighted earned common equity rate by the common equity ratio percentage.
B-2	Rate Base
B-3	Operating Income
B-4	Income Tax
B-5	Benchmark Rate of Return on Rate Base ("BRORB"). The BRORB is the composite weighted, embedded cost of capital reflecting SWEPCO's annual costs of long-term debt, preferred stock, common equity, and other capital components as of the Test Year end.
B-6	Revenue Redetermination Formula using the Rate of Return on Common Equity Bandwidth which is an Upper Bandwidth limit equal to the Target Return Rate (TRR) plus 0.5% (50 basis points) and a Lower Bandwidth limit equal to the TRR minus 0.5% (50 basis points). The TRR is the Company's cost rate for common equity as established by the Commission in Docket No. 19-008-U.
C	FRR Plan Adjustments
D	FRR Filing Requirements and description of the supporting documents to be included with the annual Evaluation Report.
E	Formula Rate Review Protocols which include the FRR general provisions and filing requirements for the annual Evaluation Report.

Attachment A-1

SOUTHWESTERN ELECTRIC POWER COMPANY
FORMULA RATE REVIEW
RATE ADJUSTMENT

All retail base rates and applicable riders on file with the APSC will be increased or decreased by a percentage of base revenues listed below, except those specifically excluded below:

Rate Class	FRR Rate (%)
Residential	XX.XXXX%
Commercial / Small Industrial	XX.XXXX%
Large Industrial	XX.XXXX%
Municipal	XX.XXXX%
Lighting	XX.XXXX%

Excluded Schedules: Energy Cost Recovery Rider (ECR)
Energy Efficiency Cost Recovery Rider (EECR)
Distribution Reliability Rider (DR Rider)

Docket No. 19-008-U
Order No. XX
Effective: XX/XX/201X
Rate Schedule No. 50

Attachment A-2

SOUTHWESTERN ELECTRIC POWER COMPANY
FORMULA RATE REVIEW
FRR RIDER REVENUE CHANGE

Line A	Description B	Total C	Residential D	Commercial / Small Industrial E	Large Industrial F	Municipal G	Lighting H
1	Base Rate Revenue: Docket No. XX-XXX-X	$	$	$	$	$	$
2	Rate Class Allocation: (Percent of Total from Line 1)	%	%	%	%	%	%
3	**FRR Constraint Calculation [1]**						
4	Total Annualized Filing Year Revenues by Rate Class	$	$	$	$	$	$
5	FRR Revenue Change ± 4% per Rate Class		4.00%	4.00%	4.00%	4.00%	4.00%
6	Upper FRR Revenue Constraint		$	$	$	$	$
7	Lower FRR Revenue Constraint		-$	-$	-$	-$	-$
9	**Calculated FRR Increase**						
10	ROE Bandwidth Rate Adjustment [2] (B-6, L 10 * L 2)	$	$	$	$	$	$
11	Incremental FRR Base Rate Change L10 ÷ (L1 + L13)	%	%	%	%	%	%
12	**Cumulative FRR Revenue Calculation [3]**						
13	Maximum Inc / Dec in FRR Revenue calculated on L9 bounded by the constraint defined on L6 and L7	$	$	$	$	$	$
14	Annualized Filing Year FRR Rider Revenue [4]	$	$	$	$	$	$
15	Cumulative Total FRR Rider Revenue (L13 + L14)	$	$	$	$	$	$
16	**Rider FRR Rate Development Calculation [5]**						
17	Adjusted Historical Base Rate Revenue (B-3, L 2)	$	$	$	$	$	$
18	FRR Rate Change (L15 ÷ L17)	%	%	%	%	%	%

NOTES:

[1] The FRR constraint calculation determines the limit of the FRR revenue increase/decrease per rate class, which shall not exceed four percent (4%) of Total Unadjusted Annualized Revenues.

[2] The Net Change in Required FRR Revenue Calculation takes the Total Historical Year Rate Change in Rider FRR Revenue (B-6, L10) and allocates the amount to each rate class based on the class allocation approved by the Commission in Docket No. 19-008-U listed on line 2.

[3] The Cumulative Rider FRR revenue calculation adjusts the required Rider FRR revenue determined on Line 10 to be within the limits of the Rider FRR constraint calculation and adds the Annualized Filing Year FRR Rider Revenue to calculate the Cumulative Total FRR Rider Revenue.

[4] The Annualized Filing Year FRR Rider Revenue in the initial Filing Year of 20XX will be zero ($0). In subsequent Filing Years, the Annualized Filing Year FRR Revenue shall reflect the annualized effect using the historical test year billing data of the FRR Rate Adjustment in effect at the end of the test year under this FRR Rider.

[5] The Rider FRR Rate Development Calculation determines the percent increase/decrease that will be applied to all base rate components. The Adjusted Historical Year Base Rate Revenue is calculated using the Retail Rate Schedule Revenue (B-3, L2) excluding Historical Year FRR Revenue and any revenue pursuant to excluded schedules on Attachment A-1. The percent increase/decrease is calculated by taking the Cumulative Total FRR Rider Revenue (L15) and dividing it by the Adjusted Historical Year Base Rate Revenue (L17).

Docket No. 19-008-U
Order No. XX
Effective: XX/XX/201X
Rate Schedule No. 50

SOUTHWESTERN ELECTRIC POWER COMPANY
FORMULA RATE REVIEW
EARNED RATE OF RETURN ON COMMON EQUITY FORMULA
Test Year Ending MMM/DD/YYYY

LINE NO	(1) DESCRIPTION	(2) REFERENCE	(3) AMOUNT
	ARKANSAS RETAIL		
1	RATE BASE	B-2, L 25, Col. 6	$
2	BENCHMARK RATE OF RETURN ON RATE BASE	B-5, L 12, Col. 5	%
3	REQUIRED OPERATING INCOME	L1 * L 2	$
4	NET UTILITY OPERATING INCOME	B-3, L 36, Col. 6	$
5	OPERATING INCOME DEFICIENCY/(EXCESS)	L 3 - L 4	$
6	REVENUE CONVERSION FACTOR (A)	Note [1]	#
7	REVENUE DEFICIENCY/(EXCESS)	L5 * L6	$
8	PRESENT RETAIL BASE RATE REVENUES	B-3, L 2, Col. 6	$
9	REVENUE REQUIREMENT	L7 + L8	$
10	COMMON EQUITY DEFICIENCY/(EXCESS) (%)	L7 / L6 / L1	%
11	WEIGHTED TEST YEAR RATE OF RETURN ON COMMON EQUITY (%)	B-5, L 3, Col. 6	%
12	WEIGHTED CALCULATED COMMON EQUITY RATE (%)	L11 - L10	%
13	COMMON EQUITY RATIO (%)	B-5, L 3, Col. 3	%
14	EARNED RATE OF RETURN ON COMMON EQUITY (%)	L12 / L13	%

NOTE:

[1] REVENUE CONVERSION FACTOR = 1 / [(1-COMPOSITE TAX RATE) * (1-FACTORING RATE) * (1-FRANCHISE TAX RATE)]

Combined Tax Rate	%
Factoring Rate	%
Franchise Tax Rate	%
Federal Rate	%
State Rate	%
Combined Tax Rate	%

Rider FRR: Attachment B-1

THIS SPACE FOR PSC USE ONLY

Docket No. 19-008-U
Order No. XX
Effective: XX/XX/201X
Rate Schedule No. 50

SOUTHWESTERN ELECTRIC POWER COMPANY
FORMULA RATE REVIEW
ARKANSAS
RATE BASE
Test Year Ending MMM/DD/YYYY

	(1)	(2)	(3)	(4)	(5)	(6)
LINE NO	DESCRIPTION	TOTAL CO PER BOOKS	TOTAL CO ADJUSTMENTS [1]	TOTAL CO ADJUSTED AMOUNT	APSC RETAIL ALLOCATION FACTOR (D)	APSC ADJUSTED AMOUNT
1	PLANT IN SERVICE					
2	Beginning Balance	$	$	$	%	$
3	Ending Balance	$	$	$	%	$
4	Average Balance	$	$	$	%	$
5	ACCUMULATED DEPRECIATION					
6	Beginning Balance	$	$	$	%	$
7	Ending Balance	$	$	$	%	$
8	Average Balance	$	$	$	%	$
9	AVERAGE NET UTILITY PLANT (L4 + L8)					$
10	PLANT ACQUISITION ADJUSTMENT					
11	Beginning Balance	$	$	$	%	$
12	Ending Balance	$	$	$	%	$
13	Average Balance	$	$	$	%	$
14	AMORTIZATION OF ACQUISITION ADJUSTMENT					
15	Beginning Balance	$	$	$	%	$
16	Ending Balance	$	$	$	%	$
17	Average Balance	$	$	$	%	$
18	WORKING CAPITAL ASSETS					
19	MATERIALS AND SUPPLIES	$	$	$	%	$
20	PREPAYMENTS	$	$	$	%	$
21	FUEL INVENTORY	$	$	$	%	$
22	WORKING CASH	$	$	$	%	$
23	TOTAL WORKING CAPITAL ASSETS	$	$	$	%	$
24	OTHER	$	$	$	%	$
25	TOTAL RATE BASE (L9+L13+L17+L23+L24)					$

NOTES:
[1] Adjustments as set forth in Attachment C to this Rider FRR.

THIS SPACE FOR PSC USE ONLY

Docket No. 19-008-U
Order No. XX
Effective: XX/XX/201X
Rate Schedule No. 50

SOUTHWESTERN ELECTRIC POWER COMPANY
FORMULA RATE REVIEW
ARKANSAS
OPERATING INCOME
Test Year Ending MMM/DD/YYYY

LINE NO	(1) DESCRIPTION	(2) TOTAL CO PER BOOKS	(3) TOTAL CO ADJUSTMENTS [1]	(4) TOTAL CO ADJUSTED AMOUNT	(5) APSC RETAIL ALLOCATION FACTOR	(6) APSC ADJUSTED AMOUNT
	REVENUES					
1	SALES TO ULTIMATE CUSTOMERS					
2	APSC RETAIL	$	$	$	%	$
3	LPSC RETAIL	$	$	$	%	$
4	PUCT RETAIL	$	$	$	%	$
5	TOTAL (Sum of L2 - L4)	$	$	$		$
6	SALES FOR RESALE	$	$	$	%	$
7	SYSTEM SALES	$	$	$	%	$
8	OTHER ELECTRIC REVENUE	$	$	$	%	$
9	TOTAL OPERATING REVENUES (Sum of L5 - L8)	$	$	$		$
	EXPENSES					
10	OPERATION & MAINTENANCE					
11	PRODUCTION	$	$	$	%	$
12	TRANSMISSION	$	$	$	%	$
13	REGIONAL MARKET	$	$	$	%	$
14	DISTRIBUTION	$	$	$	%	$
15	CUSTOMER ACCOUNTING	$	$	$	%	$
16	CUSTOMER SERVICE & INFORMATION	$	$	$	%	$
17	SALES	$	$	$	%	$
18	ADMINISTRATIVE & GENERAL	$	$	$	%	$
19	TOTAL O&M EXPENSE (Sum of L11 - L18)	$	$	$		$
20	GAIN FROM DISPOSITION OF PLANT/ALLOWANCE	$	$	$	%	$
21	REGULATORY DEBITS AND CREDITS	$	$	$	%	$
22	DEPRECIATION & AMORTIZATION EXPENSE	$	$	$	%	$
23	ACCRETION EXPENSE	$	$	$	%	$
24	AMORTIZATION OF PLANT ACQUISITION ADJ	$	$	$	%	$
25	FACTORING EXPENSE	$	$	$	%	$
26	OTHER CREDIT FEES	$	$	$	%	$
27	TAXES OTHER THAN INCOME	$	$	$	%	$
28	CURRENT STATE INCOME TAX [2]	$	$	$	%	$
29	CURRENT FEDERAL INCOME TAX [2]	$	$	$	%	$
30	DEF STATE INC TAX - NET [3]	$	$	$	%	$
31	DEF FEDERAL INC TAX - NET [3]	$	$	$	%	$
32	INVESTMENT TAX CREDIT	$	$	$	%	$
33	GAIN/LOSS - DISPOSITION OF UTILITY PLANT	$	$	$	%	$
34	OTHER (D)	$	$	$	%	$
35	TOTAL OPERATING EXP (Sum of L19 to L34)	$	$	$		$
36	NET UTILITY OPERATING INCOME (L9 - L35)	$	$	$	%	$

Notes
[1] Adjustments as set out in Attachment C to this Rider FRR.
[2] Reference Attachment B-4. See also Filing Requirement Item No. 15, MFR C-11 for additional support.
[3] See supporting schedule of calculation of adjustments and descriptions. See Filing Requirement Item No. 15, MFR C-9 & C-12.

SOUTHWESTERN ELECTRIC POWER COMPANY
FORMULA RATE REVIEW
ARKANSAS
INCOME TAX EXPENSE
Test Year Ending MMM/DD/YYYY

LINE NO	(1) DESCRIPTION	(2) TOTAL CO PER BOOKS	(3) TOTAL CO ADJUSTMENTS [1]	(4) TOTAL CO ADJUSTED AMOUNT	(5) ASPSC RETAIL ALLOCATION FACTOR	(6) APSC ADJUSTED AMOUNT
1	TOTAL OPERATING REVENUE	$	$	$	%	$
2	TOTAL O&M EXPENSE	$	$	$	%	$
3	GAIN FROM DISPOSITION OF PLANT/ALLOWANCES	$	$	$	%	$
4	REGULATORY DEBITS AND CREDITS	$	$	$	%	$
5	DEPRECIATION & AMORTIZATION EXPENSE	$	$	$	%	$
6	ACCRETION EXPENSE	$	$	$	%	$
7	AMORTIZATION OF PLANT ACQUISITION ADJ	$	$	$	%	$
8	FACTORING EXPENSE	$	$	$	%	$
9	OTHER CREDIT FEES	$	$	$	%	$
10	TAXES OTHER THAN INCOME	$	$	$	%	$
11	GAIN/LOSS - DISPOSITION OF UTILITY PLANT	$	$	$	%	$
12	OTHER	$	$	$	%	$
13	INTEREST EXPENSE [2]					
14	NET INCOME BEFORE INCOME TAXES (L1-sum(L2 to L13))			$		$
15	ADJUSTMENTS TO NET INCOME BEFORE INCOME TAX [3]	$	$	$	%	$
16	TAXABLE INCOME (L14 + L15)	$	$	$	%	$
	COMPUTATION OF STATE INCOME TAX					
17	TAXABLE INCOME (L16)	$	$	$	%	$
18	STATE ADJUSTMENTS [3]	$	$	$	%	$
19	STATE TAXABLE INCOME (L17 + L18)	$	$	$	%	$
20	STATE INCOME TAX BEFORE ADJUSTMENTS (L19 * Tax Rate) [1]	$	$	$	%	$
21	ADJUSTMENTS TO STATE INCOME TAX [3]	$	$	$	%	$
22	**STATE INCOME TAX (L20 + L21)**	$	$	$	%	$
	COMPUTATION OF FEDERAL INCOME TAX					
23	TAXABLE INCOME (L16)	$	$	$	%	$
24	STATE INCOME TAX BEFORE ADJUSTMENTS (L20)	$	$	$	%	$
25	FEDERAL ADJUSTMENTS [3]	$	$	$	%	$
26	TOTAL FEDERAL TAXABLE INCOME (L23 - L24 + L25)	$	$	$	%	$
27	FEDERAL INCOME TAX BEFORE ADJUSTMENTS (L26 * Tax Rate) [	$	$	$	%	$
28	ADJUSTMENTS TO FEDERAL TAX [3]	$	$	$	%	$
29	**FEDERAL INCOME TAX (L27 + L28)**	$	$	$	%	$

Notes
[1] Adjustments and applicable tax rates as set forth in Attachment C to this Rider FRR.
[2] Interest Expense for is Weighted Cost of Debt (COD) Rate as derived from COD elements reflected in Attachment B-5 times Rate Base per Attachment B-2.
[3] List all adjustments including descriptions in a supporting schedule. See Filing Requirement Item No. 15, MFR C-11 for additional support.

THIS SPACE FOR PSC USE ONLY

SOUTHWESTERN ELECTRIC POWER COMPANY
FORMULA RATE REVIEW
ARKANSAS
BENCHMARK RATE OF RETURN ON RATE BASE
Test Year Ending MMM/DD/YYYY

LINE NO	(1) DESCRIPTION	(2) CAPITAL AMOUNT ($) [1]	(3) CAPITAL RATIO (%)[2]	(4) COST RATE (%)[3]	(5) BENCHMARK RATE OF RETURN ON RATE BASE [4]
1	Long-Term Debt	$	%	%	%
2	Preferred Stock	$	%	%	%
3	Common Equity	$	%	%	%
4	Accumulated Deferred Income Tax	$	%	%	%
5	Pre-1971 ADITC	$	%	%	%
6	Post-1970 ADITC	$	%	%	%
7	Customer Deposits	$	%	%	%
8	Short-Term / Interim Capital	$	%	%	%
9	Current Accrued, and Other Liabilities	$	%	%	%
10	Capital Leases	$	%	%	%
11	Other Capital Items	$	%	%	%
12	TOTAL	$	%	%	%

NOTES:

[1] The capital balances for Long-Term Debt, Capital Leases, Preferred Stock, Common Equity, and ADIT shall be Test Year Ending balances consistent with Commission Order in Docket No. 19-008-U. Short-Term Debt balances and CAOL balances shall be based on the 13-month averages ending as of the Test Year end and include all accounts consistent with those ordered by the Commission in Docket No. 19-008-U. All other capital components including customer deposits shall be determined as of the Test Year end. Support for the 13 month average Short-Term debt shall be provided. Support for the CAOL balances shall include the same format and detail as required by the Filing Requirements in Attachment E, Item No. 15. A Test Year ending balance sheet should be provided as well as a reconciliation between the balance sheet and Column (2) amounts.

[2] Capital amounts each divided by the Total Capital Amount.

[3] The cost rates shall be calculated in accordance with the calculation applied by the Commission in Docket No.19-008-U. Support for the cost of Long-Term Debt and cost of Preferred Stock shall be provided in the same format and level of detail required by the Filing Requirements, respectively. Support for the Short-Term debt cost rate should include a general description of how the interest rae is determined and the same level of detail provided in the Filing Requirements in Attachment E, Item No. 15. The cost rate for Customer Deposits shall be the Commission-approved rate in effect during the year. The cost rate for Common Equity shall be that approved by Commission Order In Docket No. 19-008-U.

[4] The components in Column (5) are the corresponding Cost Rates multiplied by the associated Capital Ratio.

SOUTHWESTERN ELECTRIC POWER COMPANY
FORMULA RATE REVIEW
ARKANSAS
FRR REVENUE REDETERMINATION FORMULA
Test Year Ending MMM/DD/YYYY

SECTION 1

BANDWIDTH DEVELOPMENT

	DESCRIPTION	REFERENCE	
1	Earned Rate of Return on Common Equity ("ERR") [1]	B-1 , L 14	%
2	Target Rate of Return ("TRR") [2]	B-5, L 3, Col. 4	%
3	Upper Bandwidth Limit	Line 2 + 0.05%	%
4	Lower Bandwidth Limit	Line 2 - 0.05%	%
5	ROE Adjustment	If L1 < L4, then L2 - L1; If L1 > L3, then L2 - L1, but no adjustment if L1 ≥ L4 or L1 ≤ L3	%

SECTION 2

ROE BANDWIDTH RATE ADJUSTMENT

	DESCRIPTION	REFERENCE	
6	ROE Adjustment	per Line 5	%
7	Common Equity Capital Ratio	B-5, L 3, Col. 3	%
8	Retail Rate Base	B-1, L 1, Col. 3	$
9	Revenue Conversion Factor	B-1, L 6, Col. 3	#
10	Total Rate Change in FRR Revenue	L6 * L7 * L8 * L9	$

Notes:

[1] The ERR is the Earned Rate of Return on Common Equity calculated by dividing the weighted earned common equity rate by the common equity ratio percentage.

[2] The TRR is SWEPCO's cost rate for common equity as established by the Commission in Docket No. 19-008-U.

Attachment C
Southwestern Electric Power Company
FORMULA RATE REVIEW ADJUSTMENTS

The actual (per book) data for each Test Year reflected in Attachment B shall be adjusted to reflect the following specific ratemaking adjustments to rate base, operating income, and rate of return:

I. General

A) SWEPCO shall not record a regulatory asset or a regulatory liability representing the amount by which an FRR increase or decrease absent the operation of the 4 percent cap exceeds the actual FRR increase or decrease that is implemented pursuant to the operation of this tariff.

B) During the term of the FRR the Lost Contribution to Fixed Costs portion of the Company's Energy Efficiency Rider shall be set to zero after any true-ups, if needed, for timing purposes.

C) If not specifically mentioned in this Attachment C, revenues, expenses, cost of capital components and any other cost effects shall be treated in the same manner as in Docket No. 19-008-U.

D) Rate base amounts for the Test Year shall exclude construction work in progress (CWIP), Non-Utility Plant, and Plant Held for Future Use.

E) The Arkansas Jurisdictional Revenue Requirement will be determined by running the total company historical costs through the approved Cost of Service model from Docket 19-008-U. The Company will provide a fully-functioning cost of service model able to replicate the Company's determination of the jurisdictional revenue requirement, containing links to the supporting accounting schedules which contains the level of detail (e.g., subaccounts or detailed plant information) commensurate with the detail required by the cost of service model.

F) Plant additions requiring either CECPN or CCN approvals (generation and transmission plant) in any SWEPCO jurisdiction shall be included in this FRR, but related revenues recovered under this FRR shall be subject to refund pending a prudence review in the next general rate case, if the prudence determination doesn't occur during the FRR review. All other plant additions shall be deemed prudent once included in this FRR.

II. Cost of Service Ratemaking Adjustments

A. Rate Base

1. Use Test Year-end balances for Electric Plant In Service (EPIS) and Accumulated Depreciation on a total company basis excluding the Turk Generation Power Station and related Generator Step-up Transformers.

2. Use 13-month averages ending December 31 of the Test Year for working capital assets, excluding amounts (e.g., non-jurisdictional) and accounts consistent with Docket No. 19-008-U.

3. Restate balances of accumulated depreciation (and related depreciation ADIT) using existing Arkansas depreciation rates in effect when the depreciation expense was incurred.. During an annual FRR filing,

a utility may request an interim rate for plant added which has no approved depreciation rate, excluding major plant acquisitions. Depreciation rates for major plant acquisitions must be requested within the docket requesting approval of the purchase.

4. Remove from Test Year Rate Base all non-Arkansas jurisdictional, non-utility amounts and other items consistent with Docket No. 19-008-U.

5. Include AFUDC adjustment to EPIS, accumulated depreciation and ADIT computed consistent with Docket No. 19-008-U including Arkansas' approved return on common equity and the FERC AFUDC formula.

6. Eliminate rate base effects associated with any riders other than this FRR Rider that SWEPCO may have in effect during the test year that recover specific costs.

B. Operating Income

1. The Test Year shall reflect actual revenues. No adjustments for rate annualization, growth or weather shall be included.

2. The revenue and expense effects associated with any riders other than this Rider FRR that SWEPCO may have in effect during the test year that recover specific costs are to be eliminated.

3. Include other revenues consistent with the methodology utilized in Docket No. 19-008-U.

4. Do not annualize or normalize test year revenues or expenses, except for depreciation expense which shall be restated using approved depreciation rates and changes in EPIS.

5. Include credit line fees in operating expenses that are not included in cost of debt or recovered elsewhere in the cost of service.

6. Specifically assign jurisdictional other taxes in same manner as SWEPCO filed its revenue requirement as in Docket No. 19-008-U.

7. Exclude other costs not recognized for ratemaking, including, but not limited to, the Turk Generation Power Station, charitable contributions, lobbying expenses, fines and penalties, and disallowances consistent with Docket No. 19-008-U.

8. Adjust federal and state income expense, and deferred tax expense, for the following:
   i. All Historical Year interest expenses shall be eliminated and replaced with an imputed interest expense amount equal to the rate base multiplied by the weighted embedded cost of debt;
   ii. Effects associated with other adjustments set out in this Attachment C shall similarly and consistently be adjusted;
   iii. The corporate state and federal income tax laws legally in effect at test year end shall be reflected in the calculation of all income tax amounts; and any changes in the statutory federal income tax rate will be treated as a direct flowthrough item in the year the new tax rate is effective as long as the flowthrough complies with normalization rules; and,
   iv. Tax effects normally excluded in prior Commission Orders regarding SWEPCO for ratemaking purposes shall be eliminated.

C. Benchmark Rate of Return on Rate Base

1. Short-term Debt shall be included consistent with Docket No. 19-008-U.

2. All Long-Term Debt issues as of the Test Year end, including current maturities, shall reflect the balance net of a) unamortized debt discount, premium, and issuance expense and b) the gains or losses on reacquired debt should be included as a component of total net outstanding Long-Term, consistent with Docket No. 19-008-U.

3. All Preferred Stock issues as of the Test Year end shall reflect the balance net of discount, premium and capital stock expense, consistent with Docket No. 19-008-U.

4. Accumulated Deferred Income Taxes (ADIT) will be treated as zero-cost capital reflecting balances at Test Year-End. ADIT shall include all accounts consistent with those approved in Docket No. 19-008-U. Any associated excess ADIT recorded in the Company's Regulatory Assets/Liabilities receives the same ADIT treatment consistent with Docket No. 19-008-U.

5. CAOL shall be based on the 13-month averages ending as of the Test Year end, and include all accounts consistent with those ordered by the Commission in Docket No. 19-008-U.

6. All other capital components including customer deposits shall be determined as of the Test Year end.

7. The cost rates to be applied for Long-Term Debt and Preferred Equity shall be determined as of the Test Year end. The Long-Term Debt cost rates shall include the a) annual amortization of debt discount premium and expenses; and b) annual gain or loss on reacquired debt.

8. The cost rate to be applied for Common Equity shall be the authorized Rate of Return on Common Equity approved by the Commission in Docket No. 19-008-U.

9. The cost rates for ADIT and CAOL will be zero.

10. The cost rates for other capital items including customer deposits, short-term debt and other capital components will be determined as of the Test Year end and calculated in a consistent manner with Docket No. 19-008-U.

Attachment D

SOUTHWESTERN ELECTRIC POWER COMPANY
FORMULA RATE REVIEW
FILING REQUIREMENTS

Item No.	Filing Requirements
1	SWEPCO shall file all FRR Attachments supporting the Test Year. For the initial FRR application, SWEPCO shall provide the FERC FORM Number 1 for the test year and the four preceding years. The FERC FORM Number 1 for the test year will be provided when filed at the FERC.
The following information shall be provided to the Parties:	
2	In support of the Test Year FRR schedules, the Company will provide a fully-functioning cost of service model as approved by the Commission in Docket 19-008-U. The Cost of Service model should be able to replicate the Company's determination of the jurisdictional revenue requirement, containing links to the supporitng accounting schedules which contains the level of detail (e.g., subaccounts or detailed plant information) commensurate with the detail required by the cost of service model. Total company amounts shall be reconciled to the Trial Balances provided in item 3.
3	Monthly Trial Balances by detail general ledger subaccount number for the Test Year.
4	Identify all construction projects or purchases that closed to plant during the Test Year greater than $1 million on a total basis. Include the project number, project description, start date, completion date, date closed to plant, cost to complete, and plant accounts where it was closed. Provide the costs, including the AFUDC calculation, included in the five (5) largest projects completed during the year.
5	Rules of Practice and Procedure, Appendix 8-1 Minimum Filing Requirements (MFR) Schedules, as modified for the Test Year, B-1, B-2, B-4, B-5, B-10, C-2, C-4, C-5, C-8, C-9, C-10, C-11, C-12, D-2, D-3, D-5, D-6.1, D-6.2, D-6.3, D-7, F-1, G-1, G-2, G-3 and G-4, including the supporting cost of service study (Jurisdictional Only). For the F-1 Schedule, provide a reconciliation to Schedule B-1 and the plant amounts in the monthly trial balance (item 3 above).
6	Detailed chart of accounts, including subaccounts and detailed description (i.e. MFR E-9). List of project codes, activity codes, resource codes and detailed description for each.
7	Web access to SWEPCO's general ledger for the Test Year including capablility to view supporting invoices.
8	For the Test Year, by rate class and rate schedule, provide a monthly statement showing customer count, kWh, coincident and non-coincident kW demands, base rate revenues, and rider revenues.
9	For the 12 month's prior to the Test Year, provide actual revenues by rate class.
10	SWEPCO/AEPSC internal and external audit reports for the Test Year and any proposed auditor's adjustments to be filed confidentially.
11	The most recently filed State and Federal Income Tax Returns for SWEPCO and AEP to be filed confidentially. Also provide any return that becomes available during the discovery period related to the Test Year.

Attachment E

FORMULA RATE REVIEW PROTOCOLS
Section I. General Provisions

1. Applicability and Scope

A. The following protocols shall apply to the annual Evaluation Report filings made pursuant to the Formula Rate Review (FRR) Rider approved by the Commission in Docket No. 19-008-U.

B. The Rules of Practice and Procedure (RPPs) shall apply to all annual Evaluation Report filings, except the following for which the Commission has granted an exemption by approving the FRR:

Rule 3.08;
Rule 4.02 (a)(2)(A);
Rule 4.02 (a)(3);
Rule 4.02 (a)(4);
Rule 4.03 (c);
Rule 4.04 (a)(2);
Rule 4.10 (a)(2) & (3); and
Rule 5.05(b), (c), & (d).

C. Any proposed modification of the FRR Rider, including these protocols, is outside the scope of an annual Evaluation Report filing and as such, no Party shall seek to modify the FRR Tariff, including these protocols, as part of any annual Evaluation Report filing. Proposed modifications to the FRR Tariff, including these protocols, shall be brought in a separate docket.

D. The filing of an annual Evaluation Report is a Formal Application. The filings of an annual Evaluation Report are not to be construed as a General Rate Change Application, nor are adjustments to rates that result from the filings of an annual Evaluation Report to be construed as a general change in rates pursuant to any provision of the Arkansas Code that references a general change in rates.

E. The Commission may grant an exemption from compliance with these Protocols if the exemption is found to be in the public interest and for good cause shown.

2. Public Notice

A. At least thirty (30) days prior to filing an annual Evaluation Report, SWEPCO shall give public notice of its intent to file.

B. The notice shall indicate that it is from SWEPCO and shall include: the docket number, if known; the date on or about which the annual Evaluation Report is to be filed; the effective date of FRR rates; reference to the RPPs and these protocols for persons interested in intervening, making a limited appearance, or submitting public comments in writing or orally at the hearing; deadlines for intervention as provided herein; the name, address, phone number and email address of the Secretary of the Commission and the URL address of the Commission website; and that further information may be obtained by contacting the Secretary of the Commission or viewing the Commission's website.

C. Public notice shall be given by any method including but not limited to: bill notation, direct mail, email exploder list, publication on SWEPCO's website, through social media, or publication in a newspaper of general circulation in SWEPCO's service area.

D. An annual Evaluation Report filing shall include a declaration that these notice provisions have been complied with.

3. Intervention

A. A Petition to Intervene shall be filed within ten (10) calendar days from the date the annual Evaluation Report is filed.

B. Any Party desiring to file a Response to a Petition to Intervene shall file the Response within five (5) calendar days of the filing of the Petition. No additional responses or replies shall be permitted unless specifically authorized by the Commission.

C. The Commission shall rule on the Petition to Interveners within seven (7) calendar days from the date the Petition is filed. If the Commission does not rule within that time frame, the Petition to Intervene shall be deemed denied.

4. Discovery

A. Time Within Which to Respond or Object

1. The Party upon whom discovery is sought shall serve a written response or objection within ten (10) calendar days after service of the discovery. Responses or objections to requests for admission shall be served within ten (10) calendar days of service of the requests. The Commission may prescribe a shorter or longer time. Any objections shall state the specific reasons for such objection.

2. If the response to the discovery request contains protected information for which no Protective Order has been issued, the responsive Party shall apply for a Protective Order as soon as reasonably practicable after receipt of the discovery request so as to avoid any delays in responding to discovery, and to the greatest extent practicable no later than five (5) calendar days after receipt of the discovery request. SWEPCO shall respond to the discovery request on the next business day after the Protective Order is issued or on the date the discovery response is due.

B. Discovery Initiation

Unless otherwise ordered, a Party may initiate discovery at any time after filling of an annual Evaluation Report so long as responses or objections and depositions shall be completed at least sixty (60) days before the date on which rates determined by the formula rate review mechanism will go into effect for each year or ten (10) days before a hearing on the merits, whichever is earlier.

C. Service and Format

1. Service shall be made by electronic mail, facsimile transmission, hand delivery, or overnight delivery service unless unusual circumstances otherwise justify delivery by another method and the Parties agree to the method chosen.

2. Attachments to documents shall be provided in native electronic format, with formulae and viable links intact.

3. Any discovery document served electronically or by facsimile after Commission Business Hours but before midnight or received on a non-business day shall be deemed served on Persons on the Official Service List with electronic mail on the next business day. Any discovery document served electronically or by facsimile between midnight and the beginning of Commission Business Hours on a business day shall be deemed served on Persons on the Official Service List on that business day. Any discovery document served by hand delivery or overnight delivery service shall be deemed served pursuant to Rule 3.07 of the RPPs.

D. Computation of Time for Performance or Response

In computing the time within which an act must be performed or a response made, the Day of the act from which the designated period of time begins to run shall not be included and the last Day shall be included unless it is a Saturday, Sunday, Legal Holiday, or other Day in which the Commission's office is closed, in which event the period shall extend to the next business Day. Service by mail or commercial delivery service is prohibited; therefore no additional response time as contemplated by the RPPs is necessary.

5. General Filing Matters

A. Beginning with the initial annual Evaluation Report filing after the FRR is approved by the Commission in Docket No. 19-008-U, a separate docket shall be established by the Secretary of the Commission for the annual Evaluation Report filings with an "FR" docket designation.

B. The initial and all subsequent annual Evaluation Reports filed in the "FR" docket. SWEPCO shall submit the annual Evaluation Report with a Commission-approved tariff Docket Summary Cover Sheet. In addition to any other information required by the coversheet, SWEPCO shall reference Docket No. 19-008-U.

C. Stipulations or Settlements

1. Parties shall propose by written motion that the Commission adopt stipulations or settlements. Such motion shall be filed, along with supporting testimony, no later than seven (7) calendar days prior to the hearing scheduled in the annual Evaluation Report filing. If the seventh day falls on a weekend or state holiday such settlement agreement and supporting testimony shall be filed on the last business day prior to the seventh day. The motion shall set forth the factual, legal, policy, and other consideration which form the basis for the Parties' recommendation that the stipulation or agreement be adopted, and shall be supported by written testimony.

2. A Party not joining a proposed stipulation or settlement may file a response no later than five (5) calendar days prior to the scheduled date of the hearing.

3. Such a response shall set forth the factual, legal, policy, and other consideration which form the basis for the Party's opposition to the proposed stipulation or settlement or portions thereof.

Section II. Filing Requirements

1. Testimony and Exhibits

A. Testimony with or without Exhibits shall be filed simultaneously with the annual Evaluation Report and address, at a minimum:

1. A description of the filed schedules and all of the adjustments proposed;

2. A description of any significant cost drivers;

3. A description of any changes in accounting policies, practices, and procedures if they affect inputs to the FRR or the rate redetermination to be made under the FRR; and

4. A narrative explanation of the rate impact.

2. Workpapers and Supporting Documentation

A. The annual Evaluation Report and any revisions thereto shall include:

1. Data-populated schedules including fully functioning EXCEL spreadsheet with all formulas and links intact, showing all calculations in the annual Evaluation Report;

2. Sufficient information to enable the Parties to replicate the calculation of the formula results from the applicable schedules; and

3. Documentation fully supporting all calculations and adjustments.

B. Workpapers shall be provided to the Parties simultaneously with the filing of the annual Evaluation Report and any revisions thereto, and shall include:

1. All supporting calculations and documents that explain the calculations in the annual Evaluation Report;

2. Both references to and support from detailed source information; and

3. A complete description of any statistical model used, the data used, and the results of the analysis if not addressed in testimony or exhibits.

C. With respect to any change in accounting that affects inputs to the FRR or the resulting rate redetermination to be billed under the FRR, SWEPCO shall identify and provide narrative explanation of the individual impact of such changes on rate redetermination to be billed under the FRR including:

1. The initial implementation of an accounting standard or policy;

2. The initial implementation of accounting practices for unusual or unconventional items where the Commission has not provided specific accounting direction;

3. Correction of errors and prior period adjustments that impact the FRR;

4. The implementation of new estimation methods or policies that change prior estimates; and

5. Changes to income tax elections.

D. SWEPCO shall identify any reorganization or merger transaction and explain the effect of the accounting for such transaction(s) on the inputs to the FRR or the resulting rate determination to be billed under the FRR.

3. Waiver of Requirements

SWEPCO may omit specific items of information from the annual Evaluation Report filing only with prior Commission approval.

4. Filing Deficiencies

A. The Arkansas Public Service Commission General Staff ("Staff") may review each annual Evaluation Report filing to ascertain whether it complies with the provisions of these Filing Requirements and the FRR, including the provisions of all of the Attachments thereto.

B. If Staff determines that any deficiencies exist, Staff shall file a notice detailing the deficiencies within seven (7) calendar days from the date the annual Evaluation Report is filed.

C. SWEPCO shall correct the deficiencies, within seven (7) calendar days of filing of the notification of deficiency, or upon objection being filed by SWEPCO within that timeframe; the Commission may set a longer period as may be reasonable.

D. Staff shall review corrections made by SWEPCO to determine compliance with all information required by the Filing Requirements and the FRR, including the provisions of all of the Attachments thereto.

E. No more than three (3) business days from the filing of corrections, Staff may file a (1) statement of compliance or (2) a second notice of deficiencies, listing each requirement not met and a brief explanation in support.

F. The Commission shall resolve any dispute as to deficiencies within seven (7) calendar days of the filing of the second notice of deficiencies by either accepting the corrections made by SWEPCO or by directing additional corrections to be filed by SWEPCO.

5. Dispute Procedures

A. Any Party filing with the Commission a statement of errors or objections to the Evaluation Report shall file Testimony with or without Exhibits simultaneously with the statement of errors or objections and the filing shall:

1. Clearly identify and explain the error in or objection to the annual Evaluation Report;

2. Make a good faith effort to quantify the financial impact of the error or objection;

3. State specifically any proposed changes to the annual Evaluation Report that the Party recommends; and

4. Include all documents and workpapers that support the calculation of the error or the facts supporting the objection.

B. SWEPCO shall file a corrected FRR rate or Rebuttal Testimony with or without Exhibits to the errors and objections raised by the Parties.

6. Extension of Term

A. If SWEPCO requests an extension of the initial term of the FRR, SWEPCO shall include such request as part of its fourth annual Evaluation Report filing.

B. SWEPCO shall provide a class cost of service study for historical year-end 2023.

C. The Commission shall enter a decision on SWEPCO's request no later than 30 days after SWEPCO's request for an extension of the term.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. R-51.1 Sheet 1 of 1	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Rate Schedule No. 51		
Title: DISTRIBUTION RELIABILITY RIDER (DRR)		PSC File Mark Only

AVAILABILITY

The Distribution Reliability Rider is designed to recover Arkansas costs associated with vegetation management and tree trimming incremental to Arkansas jurisdictional costs recovered in base rates for vegetation management. The Arkansas jurisdictional portion of distribution reliability costs are those that are directly assigned to the Arkansas jurisdiction. The class allocators will be determined using the most recently approved FERC account 593 allocation factors for SWEPCO Arkansas. The Distribution Reliability Rider is applicable to and becomes part of each SWEPCO Arkansas jurisdictional rate schedule. This Rider is applicable to energy consumption of retail customers served at secondary and primary service levels and to facilities, premises and loads of such retail customers.

For service billed under applicable rate schedules for which there is not metering, the monthly kilowatt-hour (kWh) usage shall be estimated by the Company and the Distribution Reliability Factor shall be applied to the estimated kWh usage. The Distribution Reliability billing shall be determined by multiplying the total billing kWh for each applicable customer by the Reliability Surcharge Factor for that customer's class for the current month.

ANNUAL DETERMINATION

The initial period for the DRR Factors shall be the forecasted initial 12 months of distribution reliability costs. A True-up Adjustment shall be calculated and reflected in the following year's DRR factor calculation. The True-up Adjustment shall be defined as the difference between the actual DRR costs for the prior year and the revenue received from the DRR Factors. DRR factors shall be filed by the Company with the Commission and shall be accompanied by a set of workpapers sufficient to fully document the calculations of the DRR Factors including any potential True-up Adjustment.

DISTRIBUTION RELIABILITY FACTORS

Major Rate Class	Factors
Residential - Secondary	\$0.004713 per kWh
Commercial/Small Industrial – Secondary	\$0.003375 per kWh
Commercial/Small Industrial - Primary	\$0.001682 per kWh
Municipal – Secondary	\$0.003379 per kWh
Lighting – Secondary	\$0.004594 per kWh

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ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. P-1.1	Sheet 1 of 1
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Policy Schedule No. 1		
Title: EXTENDED ABSENCE PAYMENT PLAN (General Service Rule 5.11)		PSC File Mark Only

The following options are available to customers to avoid suspension of service during extended absences.

Bills coming due during the customer's absence may be paid in advance. The amount of the advance payment will be based on the customer's average monthly bill for the most recent 12 months. If less than 12 months usage history is available, the advance payment will be based on the number of months of usage history available. If the advance payment is more than the actual bill for service, the overpayment will be credited to the customer's account. If the advance payment is less than the actual bill for service, the balance due will be carried forward each month until the customer returns. Delayed payment agreements will be available for any underpayments.

The customer will be given the opportunity to enroll in the Company's Bank Draft Payment Plan whereby the monthly service bill will be paid automatically through the customer's checking or savings account.

The customer can arrange to have bills coming due during the period of the absence mailed to an alternate address or third party during the absence.

The customer must notify the Company in order to take advantage of any of these extended absence payment plans.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. P-2.1	Sheet 1 of 1
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service:	Residential & Churches
Part III. Policy Schedule No. 2		
Title: BUDGET PLAN (EQUAL PAYMENT PLAN)		

PSC File Mark Only

A "Budget", or Equal Payment Plan, is available upon request to residential Customers or churches having established satisfactory credit and having a net average monthly billing of $10.00 or more. The purpose of this plan is to provide a means of budgeting or leveling monthly payment amounts on an annual basis to avoid extreme seasonal billing fluctuations. The Equal Payment Plan is not to be used to defer payment of delinquent bills.

Company, by agreement with Customer, may accept payment for electric service in twelve (12) equal monthly payments to approximately equal the anticipated average of the next twelve (12) month billings for service. Monthly payments are determined by dividing annual billings plus a nominal growth factor by twelve. Annual billing is based upon actual history, if available, or from estimated use. Monthly payments are subject to review and quarterly adjustment, if needed, to break even at the end of each twelve (12) month period. Application may be made in person at Company's office or by mail or telephone. After Company accepts an application, Customer must sign an agreement before the plan becomes effective. The Agreement may be canceled by either party upon notice to the other party. If the Customer meets the conditions in GSR 4.02A., the plan may be cancelled. Customer may not apply for Equal Payment Plan more than one time in a twelve (12) month period at the same location. At the end of each twelve (12) month period or in the case of cancellation, the accumulated amount by which Customer's payments are more than or are less than the amount accumulated by monthly billings will be refunded or credited to Customer's account, upon request, or shall become due from Customer as of the date of cancellation or the date of the last bill rendered for the twelve (12) month period.

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ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. P-3.1	Sheet 1 of 1
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Residential	
Part III. Policy Schedule No. 3		
Title: RETIREMENT PLUS PLAN		PSC File Mark Only

The Retirement Plus Plan is available to qualified residential customers who make application for the Plan. To qualify, the applicant must provide evidence to SWEPCO that he or she is in one of the following categories:

1) Age 62 or above and receiving Social Security, Governmental, Military, or other retirement income;
2) Receiving Aid to Families with Dependent Children (AFDC), or Aid to the Aged, Blind and Disabled (AABD);
3) Persons receiving Supplemental Security Income;
4) Persons whose primary source of income is Social Security or Veterans Administration disability or retirement benefits;
5) Persons receiving disability income; or
6) Persons receiving survivor’s income.

Evidence of any of these can be supplied by providing one or more of the following:

1) Drivers license;
2) Birth certificate;
3) A copy of their check; or
4) A letter or other document to the recipient indicating that payment is being made.

The applicant also must be the SWEPCO customer of record at his or her address.

When a customer is placed on the Plan, his or her monthly electric bill will be due 30 days after the date of the mailing of the bill. This time period is applicable irrespective of contrary wording concerning due dates which may be found elsewhere in these tariffs.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. P-4.1	Sheet 1 of 2	
Replacing:	Sheet No.		
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY			
Kind of Service: Electric	Class of Service:	Residential & Churches	
Part III. Policy Schedule No. 4			
Title: AVERAGE MONTHLY PAYMENT PLAN (Levelized Billing)			PSC File Mark Only

An Average Monthly Payment Plan is available upon request to residential customers or churches who do not have past-due accounts. The purpose of this plan is to provide a means of budgeting or leveling monthly payment amounts on an annual basis to avoid extreme seasonal billing fluctuations. The Average Monthly Payment Plan is not to be used to defer payment of delinquent bills.

Company, by agreement with customer, may accept an average payment amount for electric service that is based on the current month's billing, plus the eleven (11) preceding months, divided by twelve (12). At the next billing period, the oldest month's billing history is dropped, the current month's billing is added, and the total is again divided by twelve (12) to find a new average payment amount. In such instances where sufficient billing history is not available, an Average Monthly Payment Plan amount may be established by using an estimated average payment amount. When sufficient billing history (six months) has been attained, the system will automatically compute the new average payment amount based on actual billing history.

The difference between actual billings and the averaged billings under the Average Monthly Payment Plan will be carried in a deferred balance that will accumulate both debit and credit differences for the duration of the Average Monthly Payment Plan year -- twelve (12) consecutive billing months. At the end of the Average Monthly Payment Plan year (anniversary month), the current month's billing, the eleven (11) preceding month's billing, and the net accumulated deferred balance will be summed, and the totals divided by twelve (12) to derive a new average for the new plan year. The deferred balance (debit or credit) is then applied to the billing amount due.

Settlement occurs only when participation in the plan is terminated. Settlement happens if an account is final billed, if the customer requests termination, or if terminated by the Company as a result of past-due amounts on an account. In the case of termination, the accumulated amount by which customer's payments are more than or are less than the amount accumulated by monthly billings will be refunded or credited to customer's account, or shall become due from customer as of the date of termination or the date of the last bill rendered for the twelve (12) month period.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. P-5.1	Sheet 1 of 1
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Policy Schedule No. 5		
Title: VOLTAGE VERIFICATION PLAN		

PSC File Mark Only

Southwestern Electric Power Company has permanently installed, at each of its distribution substations, voltmeters that verify voltage levels by recording continual voltage readings.

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ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. P-6.1	Sheet 1 of 1
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Policy Schedule No. 6		
Title: STANDARD NOMINAL VOLTAGES		PSC File Mark Only

<u>Nominal Voltages - Secondary</u>

The following secondary voltages are available from the Company depending on the customer's size, application, and location on its distribution system:

Single Phase:	120/240	120/208	480		
Three Phase:	120/240	240/480	120/208	277/480	2400/4160

<u>Nominal Voltages - Primary</u>

The following primary voltages are available from the Company depending on the customer's size, application, and location on its distribution system:

7200/12,470	19.9/34.5 kV	2400/4160

<u>Other Voltage Service</u>

Depending on the customer's size, application, and location, customers requiring other voltages may be served through special arrangements under written agreements.

ARKANSAS PUBLIC SERVICE COMMISSION

Original | Sheet No. P-7.1 | Sheet 1 of 1

Replacing: | Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric | Class of Service: Residential

Part III. Policy Schedule No. 7

Title: PROVISIONS FOR LANDLORDS AND TENANTS
(General Service Rule 6.19)

PSC File Mark Only

Account Identification

The Company has established the following procedures for identifying accounts where utility service is provided at an address different from the mailing address of the bill:

A. When application is made for service, Company personnel will inquire as to whether the account qualifies as a landlord/tenant situation as described by GSR 6.19.A.

B. Information regarding the identification of such accounts will be provided to applicants upon application for service in the Company's Information to Customers booklet.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. P-8.1	Sheet 1 of 1
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Policy Schedule No. 8		
Title: METER TESTING PROGRAM		

PSC File Mark Only

Test Program for New Meters

To ensure that new meters conform to the accuracy requirements of SR-E 7.05.B., before installation by the Company, all new meters will be inspected and tested in a meter shop or laboratory under the sampling method indicated below:

_____ 100% of all new meters will be tested.
__X__ New meters will be tested on a sampling basis conforming to ANSI C12.1-1982, § 8.1.5.

In-Service Meter Testing Program

In accordance with SR-E 7.08.B., all in-service meters will be tested by the Company under the program indicated below: (All meters will be tested under the same program.)

_____ Periodic interval ANSI C12.1-1982, § 8.1.8.4. and § 8.2.3.1.
_____ Variable interval ANSI C12.1-1982, § 8.1.8.5.
__X__ Statistical sampling ANSI C12.1-1982, § 8.1.8.6.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. P-9.1	Sheet 1 of 1
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: Industrial, Commercial and Municipal	
Part III. Policy Schedule No. 9		
Title: SUMMARY BILLING PROGRAM		PSC File Mark Only

The Summary Billing Program is available upon request to multi-account commercial, industrial and municipal customers with a single monthly statement for all accounts. The Summary Billing Program will be a completely voluntary service.

The commercial, industrial and municipal customers who elect to participate in the Summary Billing Program will be required to sign an agreement for one (1) year, which may be extended by consent of the parties. Either party may cancel the agreement upon thirty (30) days written notice to the other party.

Participants in the Summary Billing Program will receive a single monthly statement which indicates, as line items, the amounts owed for each separate account. The customer will also be provided a separate report which details individual activity.

There will be no charge to the customer for the summary billing service.

Customer summary bill will be due within sixteen (16) days from the date of issuance of the summary bill.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. P-10.1 Sheet 1 of 1	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: All	
Part III. Policy Schedule No. 10		
Title: CUSTOMER PAYMENT CENTERS		PSC File Mark Only

The Company has made arrangements with a network of merchants throughout the service territory to accept SWEPCO customers' electric bill payments. The Company has contracted with a vendor to offer this service, and the vendor is responsible for securing, contracting, training, monitoring, auditing, and paying all pay station agents. A list of these authorized pay stations including hours of service, and applicable fees can be found on the Company's website at http://www.swepco.com/account/bills/pay/PayInPerson.aspx. This information can also be obtained by calling 1-888-216-3523 for English or 1-888-216-3505 for Spanish.

Most pay stations charge the customer a fee of $1.50 per transaction, but there are also locations with no fee. The customer must provide either their 11-digit electric account number or a bill stub when making payment and SWEPCO receives immediate electronic notification of the payment.

The Policy Schedule does not modify or supercede any of the provisions of any of SWEPCO's filed and approved rate schedules, in particular, the requirement that the Customer must pay the full amount of the invoice by its due date to avoid penalty remains unchanged. The Company assumes no responsibility for late payments when such payments are received after the due date.

This Policy Schedule is subject to the Standard Terms and Conditions of the Company and the rules of the Arkansas Public Service Commission.

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. P-11.1 Sheet 1 of 4	
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Policy Schedule No. 11		
Title: CONTRACT POLICY		PSC File Mark Only

At the Company's discretion, the attached contract form is utilized to show the agreement under which the Customer receives and the Company delivers electric service. The contract form may be utilized when the Company provides service under the following rate schedules:

General Service	Rate Schedule No. 5
Lighting and Power	Rate Schedule No. 6
Large Lighting and Power	Rate Schedule No. 7
Lighting and Power – Time of Use	Rate Schedule No. 8
Pulp and Paper Mill Service	Rate Schedule No. 9
Municipal Service	Rate Schedule No. 10
Municipal Pumping	Rate Schedule No. 11
Supplementary, Backup, Maintenance and As-Available Standby Power Service	Rate Schedule No. 28
Experimental Economic Development Rider	Rate Schedule No. 32
Experimental Curtailable Service Rider	Rate Schedule No. 36

Form 702-A
Rev. July 2002

This contract cancels and supersedes previous contract with (name, date, contract number): ________

____

Southwestern Electric Power Company

CONTRACT FOR ELECTRIC SERVICE

Arkansas

Contract Number ____________

____
hereinafter called "Customer", and Southwestern Electric Power Company, hereinafter called "Company", enter into the following contract:

The Company will sell and deliver to the Customer at ____

____
and the Customer will receive and pay for electric service for a period of _____________ years beginning ____, and thereafter, in automatically recurring yearly periods, unless and until terminated at the end of any yearly period by 30 days prior written notice from either party to the other. Electric service will be delivered and received hereunder in accordance with the standard Terms and Conditions which are attached and made a part of this contract, and Customer agrees to observe and be bound by them.

Electric service delivered by the Company to the Customer will be _______________ wire __________________ phase, 60 cycle, alternating current at a nominal voltage of ____________________, in the amount of approximately __________________________ kilowatts, and will be metered at ______________________ volts.

The Customer will use such electric service in the operation of __________________________________ ____ and will be billed and will pay for this service in accordance with the rate schedule attached to this contract and made a part hereof.

The following rate schedule and any special terms are applicable to this contract: _______________ ____ ____ ____

In consideration of the investment on the part of the Company to make electric service available under this contract, the minimum monthly bill will not be less than the charge for _________________________ plus the fuel and tax adjustment clauses provided in the rate schedule.

In the event a new or revised rate schedule applicable to service under this contract is authorized and made effective by the duly constituted regulatory authority or authorities having jurisdiction in the premises, which said rate schedule supersedes or modifies the rate schedule which is attached to this contract, then from and after the date upon which said new or revised rate schedule becomes authorized and effective, electric service to Customer will be billed and Customer will pay for such service in accordance with such new or revised rate schedule.

If Customer fails to perform any of his obligations under this contract, including the prompt payment of monthly bills, or fails to observe or comply with any of the attached Terms and Conditions, the Company may suspend delivery of electric service and will not be liable in any manner for loss or damage arising through such suspension. No such suspension will interfere with the enforcement by the Company of any other legal right or remedy nor relieve the Customer from liability to pay the minimum charge during any suspension. No delay by the Company in enforcing any of its rights hereunder will be deemed a waiver of such rights nor will waiver by the Company of any default by Customer be deemed a waiver of any other or subsequent default.

The Customer will indemnify and save the Company harmless from all loss on account of injury or damage to persons or property on the Customer's premises, and at and from the point of delivery of power if such point is located off the Customer's premises, growing out of any accident or mishap relating to the electric service provided by the Company to the Customer hereunder, other than any such injury or damage growing out of the gross negligence or willful misconduct of the Company or any employee or agent of the Company.

This agreement may be assigned by the Customer only with the written consent of the Company. This contract will bind and benefit the successors and assigns of the Company, and, at the option of the Company, the successors and assigns of the Customer. This contract supersedes all prior agreements between the Customer and the Company for the service specified herein.

In witness whereof, the parties hereto have caused this contract to be executed on (X) ____________________________, 20 ______.

____
Customer

Witness (X) _________________________________
(For the Customer)

By (X) ____

(X) ____
Official Capacity

SOUTHWESTERN ELECTRIC POWER COMPANY

Witness _______________________________
(For the Company)

By ____

____
Official Capacity

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No. P-12.1	Sheet 1 of 5
Replacing:	Sheet No.	
Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY		
Kind of Service: Electric	Class of Service: As Applicable	
Part III. Policy Schedule No. 12		
Title: EMERGENCY CURTAILMENT POLICY		PSC File Mark Only

APPLICABILITY

The provisions of this Emergency Curtailment Policy Schedule shall apply at any time, and for such periods of time, when in the judgment of the Company, it is necessary to reduce the use of electricity when emergency conditions exist on the electrical system as described below. This plan is to mitigate the effects of the event relative to the transmission system, generator capacity and energy emergencies of the Company.

SYSTEM EMERGENCY

Immediate and appropriate action shall be taken by the Company should a system emergency exist. A system emergency condition is defined by one or more of the conditions below.

- Serious shortages of generation capacity
- Loss of generation units
- Loss of bulk transmission
- Suspected or confirmed activity (e.g., terrorist activity, sabotage, equipment failure) which appears aimed at causing instability on the transmission system.

EMERGENCY PROCEDURES - CAPACITY SHORTAGE

The following curtailment steps will be implemented in the order listed and as necessary to reduce system loads within the capability of available generation and interconnected system purchases. Every reasonable effort will be made to assure the electrical service is not interrupted to critical customers and other loads vital to human and public needs.

1. Operating Reserve Warning
    a. First step in our Capacity Deficiency emergency procedures.
    b. SCC (System Control Center) to issue notification of ORW.

APSC FILED Time: 2/28/2019 2:15:14 PM: Recvd 2/28/2019 2:14:10 PM: Docket 19-008-U-Doc. 39

2. Maximum Emergency Generation
   a. The use of oil firing to regain lost generation that has occurred due to curtailments caused solely from loss of gas firing capability. Larger orifice plates in the oil lighter tips are required. If the unit is at full load (wide-open valves), no additional capacity is available.
   b. All units with hot start capability will be brought on-line.
   c. The utilization of overpressure and/or the removal of feedwater heaters results in additional capability that may be utilized for limited daily periods depend on unit condition and frequency of use.

3. Curtailment of Generating Plant Use
   Limiting the operation of non-critical plant activities brings about the curtailment of generating plant use. This would usually consist of the curtailment of coal handling, the shutting down of the machine shop to the extent practical, and the curtailment of lighting or air conditioning load.

4. Curtailment of Non-Essential Building Load in all SWEPCO facilities
   Request our employees cut back usage to the greatest extent possible in Company facilities.

5. Curtailment of Short Term Deliveries (SCC dispatcher notifies FERC)
   The curtailment of Non-Firm transactions supplied from AEP generation.

6. Interruptible Customers (SCC dispatcher notifies FERC)
   Curtail electric service to customers whose contracts provide for interruption under these conditions.

7. Public Appeal (SCC dispatcher notifies FERC)
   a. Appeal to all customers via press, radio, and television to cut back use of energy during the period of the emergency.
   b. Request bulk power users (municipalities and REA cooperatives) to which the Company supplies power on a wholesale basis to request their customers to cut back use of electric energy to the greatest extent possible.
   c. Request certain large industrial customers to curtail use of electric power by shifting loads to off-peak periods, to stagger operation of equipment, and to take whatever additional steps are possible to reduce electric use.

8. Purchase Non-Firm and/or Firm emergency energy to supply AEP - SWEPCO internal load requirements (if available).

.

9. Mandatory Load Shed (manual load shed)
Implement if steps 1 through 8 do not provide the necessary reduction in load. (DOE Report Required)
   a. This program utilizes distribution feeders that can be manually interrupted upon order of the SCC and/or TDC. This order may be given under conditions of extreme capacity deficiency and declining frequency. In case of a sudden deterioration of frequency or overloaded ties, it may be necessary to start this step
   b. Before the preceding step is utilized the order to interrupt will specify the amount of load or number of blocks\steps to be interrupted in order to relieve the emergency.
   c. The periods of interruption will be approximately two-hours. During the circuit rotation the circuits in one step will be opened before previously opened ones are reclosed. Interruption of distribution feeders will normally be done on a rotational basis to minimize cold-load pickup problems and to minimize interruption to Customers.

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. P-12.4 Sheet 4 of 5

Replacing: Sheet No.

Name of Company SOUTHWESTERN ELECTRIC POWER COMPANY

Kind of Service: Electric Class of Service: As Applicable

Part III. Policy Schedule No. 12

Title: EMERGENCY CURTAILMENT POLICY

PSC File Mark Only

LOAD SHEDDING CRITERIA

The circuits should be prioritized by the following guidelines. Priority 3 circuits will be shed first, then Priority 2, and if more load is needed, even Priority 1. Stations that have at least 2 feeders will be selected and each feeder should have at least 3000 kW of load. Stations with supervisory control and meeting the above criteria should be selected since we can ultimately utilize them in a computer program. At least 25% of SWEPCO's peak summer/winter internal load is included in the manual load shed plan.

Priority 1 – "Hospitals" which shall be limited to major institutions providing critical care to patients.

Priority 2 – Police, fire, communication services, water and sewer services, government, transportation, emergency medical services, alternate energy and food services.

Piority 3 – All other customers.

Life Support

Due to the vast number of distribution circuits with life support; if a circuit only has life support on it, it should be classified as a Priority 3. The life support equipment is required to have a backup power supply and will ride through any of the abnormal circuit outages experienced everyday.

CUSTOMER COMPLIANCE

In the event any customer above who has been requested to reduce or reschedule use of power and energy, fails to comply with a request of a Company representative to do so pursuant to this plan, the Company shall have the right to totally discontinue service to said customer without further notice during the period this plan is in effect. Such discontinuance shall not be deemed a violation of law or the Rules and Regulations of the Commission, and the Company shall not be liable for penalties or damages, direct or indirect, by reason thereof; provided, however, that upon taking such action, the Company shall forthwith notify the Commission of the identity and location of the customer and the circumstances leading to such discontinuance.

REPORT TO COMMISSION

As soon as practical after the implementation of all or any part of this plan, the Company shall report to the Commission in writing the reason for the emergency curtailment, the substations and circuits affected, the number of customers affected along with the beginning and ending time and duration of the emergency curtailment.

AEP EMERGENCY OPERATING PLAN (EOP)

The AEP Emergency Operating Plan (EOP) provides the guidance for Southwestern Electric Power Company (SWEPCO) during any type of bulk power interruption to the reliable power supply for the SWEPCO service territory.

A copy of the current EOP is filed in Docket No. 10-059-U with the Arkansas Public Service Commission.

The plan provides for the following:

(a) The procedures that will be employed by the utility to communicate with the public concerning an impending and/or during a system emergency or power shortage including public appeals for voluntary load reductions and energy conservation and educational messages on how to accomplish such load reduction and conservation. The EOP also addresses notification of appropriate government agencies as the various steps of the emergency plan are implemented.

(b) The procedures that will be employed by the utility for load management, voltage reductions, and curtailment of power of its retail load that will minimize adverse impacts to customers while maintaining overall system reliability. The EOP also addresses the needs of critical loads essential to the health, safety and welfare of the community.